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Outer Continental Shelf Pre-Construction Air Permit Application Revised

Frontier Discoverer Chukchi Sea Exploration Drilling Program

PREPARED FOR:
SHELL OFFSHORE INC.

PROJECT NO. 180-15
FEBRUARY 23, 2009

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GLOSSARY

The Ice Management Fleet is the group of vessels while within 25 miles of the Drill Site with the primary purpose of breaking and/or diverting the ice in ice floes that might contact the *Discoverer*. This fleet has the secondary purpose of handling the *Discoverer* anchors.

The Oil Spill Response (OSR) Fleet is the group of vessels while within 25 miles of the Drill Site with the primary purpose of being prepared for the unplanned event of an oil spill at the Drill Site, including cleanup activities.

A Planned Well is a well selected in advance of the drilling season that is drilled to collect discrete information from a specific prospect.

A Drilling Day is any day that the *Discoverer* is physically attached to the sea floor by at least one anchor for the expressed purpose of conducting drilling operations.

A Drill Site is a location on the surface of the water occupied by the *Discoverer* in any one calendar year, and from this location the *Discoverer* is permanently or temporarily attached to the sea floor and erected thereon and used for the purpose of exploring resources there from. The site includes the area surrounding the planned well within a 1,000-meter radius of the planned well. The *Discoverer* is said to be occupying a Drill Site when at least one of its anchors is attached to the sea floor.

Outer Continental Shelf (OCS) Source Activities include the following activities:

- Air pollutant emitting activities undertaken by *Discoverer* emission units listed in Table 2-1 of this application and occurring while the *Discoverer* is occupying a Drill Site, and
- Air pollutant emitting activities undertaken by support vessel emission units listed in Table 2-1 of this permit and occurring while: a) the support vessel is physically attached to the *Discoverer*, and b) the *Discoverer* is occupying a Drill Site.
- Emission units generating output exclusively for the purpose of propelling a vessel are not considered to be engaging in OCS Source Activities.

An Exploratory Operation is the collection of all OCS Source Activities undertaken to construct a Planned Well and any other wells at that drill site during one season.

The Exclusion Zone is an area defined on the sea surface by a circle with a radius of 1,000 meters centered on the well being drilled at that time. The public is restricted from the exclusion zone for it safety and the protection of the drilling operation equipment.

Abbreviations/Acronyms

AAC.......................... Alaska Administrative Code
AC............................ Intake air cooling
ANSER..................... Arctic North Slope Eastern Region
ASTM .... American Society of Testing and Materials
APD.......................... Application for Permit to Drill
BACT........................ Best available control technology
BP............................. British Petroleum
BPX.......................... British Petroleum Exploration
BPIP......................... Building Profile Input Program
CAA......................... Clean Air Act
CDPF....................... Catalytic diesel particulate filter
CEM......................... Continuous emissions monitor
CFR.......................... Code of Federal Regulations
CI .... Compression ignition
CISWI...................... Commercial and industrial solid waste incinerator
CPAI........................ Conoco Phillips Alaska Inc.
Discoverer .... Frontier *Discoverer* Drillship
DPF.......................... Diesel particulate filter
EAC .... Early action compact
EDMS .... Emissions Data Management System
EGR .... Exhaust gas recirculation
Em............................ Emergency
EPA.......................... United States Environmental Protection Agency
ESP........................... Electrostatic precipitators
FGR.......................... Flue gas recirculation
GCP .... Good combustion practices
GMP .... Good maintenance practices
HIP .... High injection pressure
HPU......................... Hydraulic power unit
I.C. .... Internal combustion
ITR........................... Ignition timing retard
LAER....................... Lowest achievable emission rate
LNB .... Low NO_x burner
LND......................... Low NO_x design
LSF........................... Low sulfur fuel
MLC......................... Mud line cellars
MSW........................ Municipal solid waste
NA .... Not Applicable
NAAQS................... National Ambient Air Quality Standards
NAICS..................... North American Industry Classification System
NESHAPs .... National Emission Standard for Hazardous Air Pollutants
NSPS........................ New source performance standard
NSR .... New source review
OCS .... Outer Continental Shelf
ORR......................... Owner Requested Restriction
OSR.......................... Oil Spill Response
OxyCat.................... Oxidation catalyst

PCV .... Positive crankcase ventilation
PSD........................... Prevention of significant deterioration
RACT........................ Reasonably available control technology
RBLC .... RACT/BACT/LAER Clearinghouse
RICE .... Reciprocating internal combustion Engines
SCR........................... Selective catalytic reduction
SDS .... Semi-dry scrubber
SIA .... Significant impact area
SIL............................. Significant impact level
SNCR........................ Selective non-catalytic reduction
SOF .... Soluble organic fraction
SSBOP .... Subsea blowout preventer
Starbd .... Starboard
ULSD........................ Ultra-low sulfur distallate fuel (15 ppm sulfur content)
Unit ID .... Emission Unit Identification Number
WI .... Water Injection
WRAP .... Western Regional Air Partnership

Units and Measures

g .... grams
gph............................ gallons per hour
bhp............................ brake horsepower
hp.............................. horsepower
km............................. kilometers
kts .... knots
kW .... kiloWatts
lbs .... pounds
MMBtu..................... million British thermal units
ppm .... parts per million
tph............................. tons per hour
tpy............................. tons per year

Pollutants

CO............................. Carbon Monoxide
H_2S............................ Hydrogen Sulfide
HAPs .... Hazardous Air Pollutants
HC .... Hydrocarbons
NMHC .... Non Methane Hydocarbons
NO_X .... Oxides of Nitrogen
NO_2........................... Nitrogen Dioxide
PM_{10}.......................... Particulate Matter with an aerodynamic diameter less than 10 microns
$PM_{2.5}$ .... Particulate Matter with an aerodynamic diameter less than 2.5 microns
SO_2 .... Sulfur Dioxide
SO_3 .... Sulfur Trioxide
VOC.......................... Volatile Organic Compounds

SECTION 1

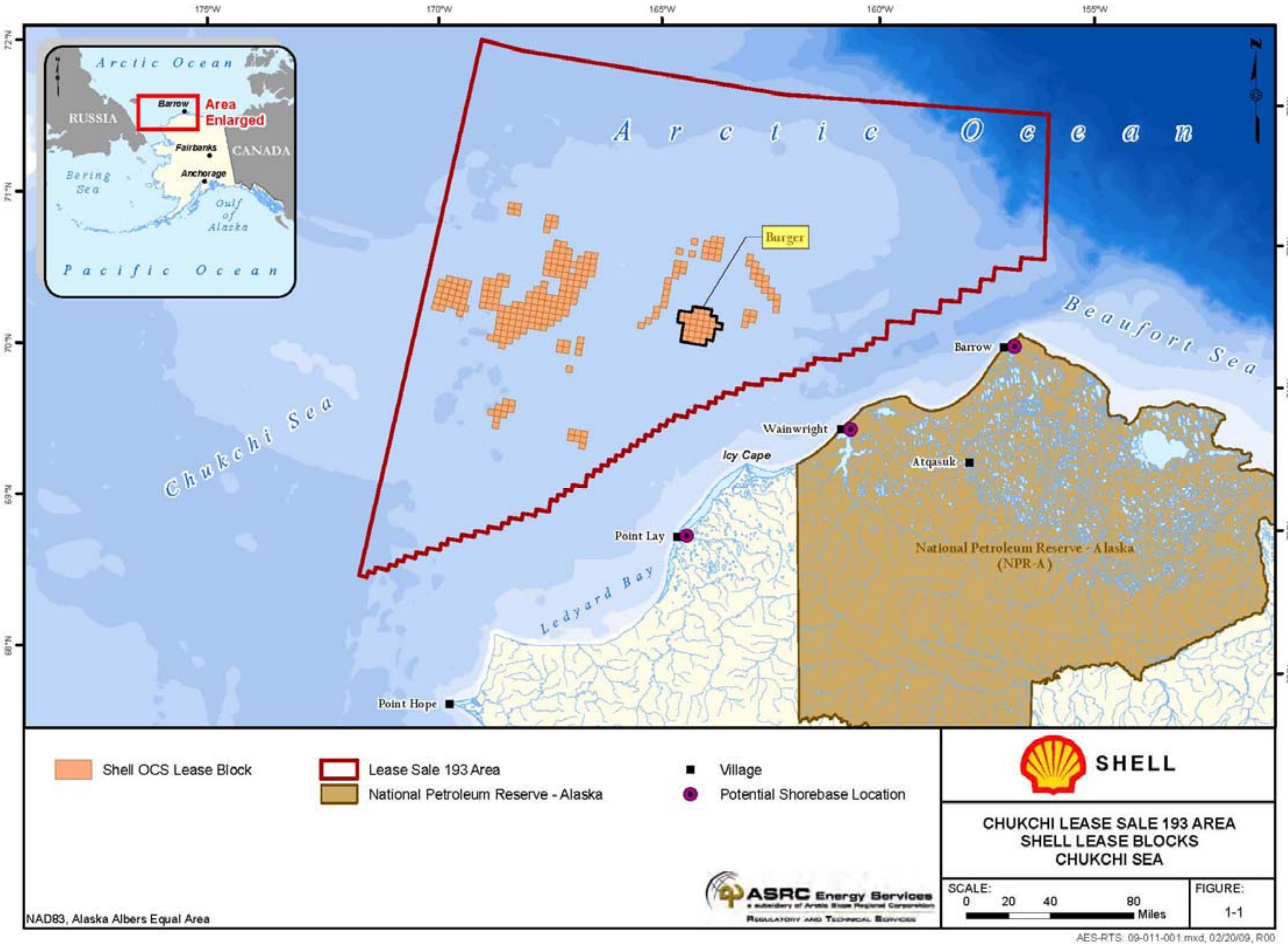
INTRODUCTION

Shell Offshore Inc. (Shell) is applying for a preconstruction permit from EPA Region 10 for the operation of the *Discoverer* drillship (source) and associated fleet in the Chukchi Sea beyond the 25-mile Alaska seaward boundary. It is to be used for exploratory drilling activity (NAICS category 211111) on the Outer Continental Shelf (OCS) of the Chukchi Sea. As such, the application is made under the OCS permitting rules (40 CFR 55). The source will trigger major stationary source classification (40 CFR 52.21 (b) (1) (i)) and therefore, as prescribed in the OCS permitting rules, this application also addresses the federal New Source Review Permitting Rules (40 CFR 52.21).

The application is for a portable major source permit to allow the *Discoverer* and its associated fleet to operate at any of Shell Gulf of Mexico Inc.'s current leases within the Chukchi Sea, all of which are beyond the 25-mile Alaska seaward boundary. Shell anticipates a drilling season of maximum 168 drilling days (5.5 months), beginning in July of each year. During this season, it would have the flexibility of drilling one or more wells or parts of wells, subject to the limitation that drilling at no single drill site would consume more than 84 drilling days. It is likely that the environmental conditions (ice) will limit the drilling season to less than these maxima. Drilling is planned to begin earliest July of 2010 and continue seasonally until the resource is adequately defined.

Figure 1-1 shows the location of the current Shell Gulf of Mexico Inc. leases in the Chukchi Sea on which the *Discoverer* is to be permitted to operate. This region can be described as lying west of Wainwright (162° west longitude) and north of Point Lay (71° north latitude).

Figure 1-1: Shell Gulf of Mexico Inc. Current Leases in the Chukchi Sea



SECTION 2

PROJECT DESCRIPTION AND EMISSIONS

The *Discoverer* is a drillship, converted for drilling in 1975 and substantially upgraded in 2007. It is equipped with generators for the drilling systems and associated self-powered equipment (such as air compressors, hydraulic pumps, cranes, boilers and other small sources), thrusters for positioning, and an emergency generator for the critical non-drilling loads when the main power supply is not operating. A listing of the *Discoverer* emission units is provided in Tables 2-1 and 2-2. Except for the air compressors all of the source units are existing equipment. The mud line cellar (MLC) air compressors will be new engines. A photograph of the *Discoverer* is provided on Figure 2-1 and the locations of the various emission units on the *Discoverer* are shown on Figure 2-2. These locations are important for the estimation of their impacts, discussed in greater detail in Section 5.

Prior to mobilizing to the Chukchi Sea, the drillship is provisioned with sufficient supplies required to drill the initial drilling operations. Together with the ice management and anchor handler fleet, consisting of an icebreaker and an arctic class anchor handler/ice management vessel, the rig mobilizes to the desired location. Alternate locations are available in the event that ice conditions at the desired location exceed the fleet's capability to manage ice or conduct operations. Anchors are run and set by the anchor handler/ice management vessel; the mooring lines are tensioned; and the rig is thus positioned over the well.

Upon completion of the mooring operation, the process to drill the MLC is initiated. The MLC is a 20 feet diameter hole excavated to approximately 35 feet below the mud line. The MLC permits installation of the rig's Subsea Blowout Preventers (SSBOP's) below the mud line to avoid damage by ice keels should ice floes force the rig off the well. Utilizing compressed air, the excavated seabed material is lifted out of the MLC and settles to the surrounding seafloor. The MLC operation is estimated to take about six days. A 36 inch diameter hole is drilled for the next interval and a 30 inch diameter tube (casing) is installed and cemented. Cementing the casing anchors it in the hole and prevents annular formation fluid migration between formations or to the surface. Atop the 30 inch casing is a guide base with receptacles for guidelines that facilitate reentry into the well.

After drilling and installing casing in the next interval, the SSBOP's are installed in the MLC. At this point the Oil Spill Response (OSR) fleet generally must be in position and be prepared to deploy in the unlikely event of an oil spill. Additional intervals are drilled, cased, and cemented as required to reach and evaluate the geologic objective.

Upon completion of the evaluation operations, the well is properly secured or plugged and abandoned (P&A'd) using mechanical and/or cement plugs, or temporarily abandoned (T&A'd), which generally occurs upon completion of any of the interim operations of cementing the casing.

After the well is abandoned the SSBOP's are retrieved. The anchors can then be retrieved and the rig can depart the drill site. The rig can move from the drill site after plugging and abandoning P&A'ing or T&A'ing a well.

The rig may leave a drill site for a variety of reasons including P&A or T&A activities, adverse ice conditions, end of the drilling season, or desire to move to another drill site to start or finish a well previously T&A'd. If for any reason a second well is to be drilled within the 1,000-meter radius of the initial well, the second well will be restricted by the air permit as if it were an extension of the initial well that established the drill site. If the *Discoverer* moves more than 1,000-meter from the first well, it establishes a new drill site and restarts the clock on the air permit restrictions.

The *Discoverer* is a turret-moored drillship that underwent significant upgrades in 2007 so that it could operate in the arctic. The *Discoverer* crew works 12-hour shifts and lives on the rig in accommodations located at the stern of the ship. They work for three to four weeks and are transported to and from the rig by helicopter to Wainwright or Barrow, Alaska.

The calculations of emissions for all emission units are shown in Appendices A and B, with the calculations on a per-emission-unit per page format in Appendix A and the calculations which feed into the impact modeling in Appendix B. Appendix A information flows from the Appendix B spreadsheets. Table 2-1 represents the maximum hourly emission rates for all the emission units of the *Discoverer* and associated fleets that could operate simultaneously. Shell requests several Owner Requested Restrictions (ORRs) that limit the short-term (up to 24-hours) operations and emissions for modeling purposes and these are incorporated in the emission calculations used for modeling (Appendix B, Page 2). The short-term engine and heater emissions are estimated using the engine or heater capacities converted to fuel heat consumption. Then these capacity consumption values are converted to emissions using manufacturer or generic (when model-specific factors are not available) emission factors. Then short-term ORRs (restrictions over a single day), Table 2-3, are applied as are the tailpipe control device guaranteed or estimated control technology efficiencies, Table 2-4. Shell's expectation of Best Available Control Technology (BACT) in the form of fuel quality and tailpipe control efficiencies are incorporated in Tables 2-3 and 2-4. BACT selection is discussed in Section 4. The long-term (seasonal) ORRs, also in Table 2-3, are taken into account through a restriction in the length of operating season in the impact modeling phase. Incinerator emissions are calculated on the basis of emissions per unit charge and using an EPA generic emission factor since no manufacturer's emission factors are available for this small device.

2.1 Generators (FD-1 through FD-6)

Six Caterpillar D399 generator sets provide the primary systems power for the drilling as well as the ship utilities and are operational at varying load levels throughout the drilling process. There are six emission units that comprise the capacity to routinely generate electrical power, with the expectation that no more than five engines will operate at one time, leaving one as a spare. The normal ramping procedure is to operate the fewest number of engines needed to power the load and as load increases to add on engines so that the operating engines are at 50 percent capacity or greater. In recognition of the excess capacity and to limit maximum emissions, Shell requests the continuous electrical production limit of 80 percent of the six-engine design capacity as an ORR shown on Table 2-3.

The generators will be retrofitted with selective catalytic reduction and oxidation catalyst control devices with control efficiencies as shown in Table 2-4. These controls are to be retrofitted by D.E.C. Marine AB, a Swedish company who has installed more NO_x ship emission control systems than any other company in the world.[1] The D.E.C. Marine AB control guarantees for NO_x, CO, and VOCs are provided on Table 2-4. Control of particulate matter is estimated from an EPA report. Except for startup and shutdown, these engines will be operated at 50 percent capacity or greater so that the emission control devices will function effectively. Regarding the control efficiency of volatile organics by the oxidation catalyst, D.E.C. Marine AB has stated that the efficiency is related to the complexity of the volatile. Complexity is judged in terms of the number of carbon atoms of the organic compound; the more carbons, in general, the lower the control efficiency will be. The lower end of the typical range of control efficiency is assumed in the emissions calculations herein.

2.2 Generator SCR Ammonia Slip

Selective catalytic reduction (SCR) is being proposed for the *Discoverer* to reduce the NO_x emissions from the main driver engines (Caterpillar D399s). The SCR technology involves the injection of urea into the exhaust stream with a catalyst to convert the NO_x to nitrogen and water. Ideally, the urea will reduce NO_x at a 1-to-1 ratio. However, because mixing within the stack is not ideal, a small portion passes through the system converted to ammonia but not to nitrogen and water and is released to the atmosphere (a process known as ammonia slip). The amount of ammonia slip from an SCR control device will theoretically begin at near zero and increase over the life of the catalyst (8 to 10 years). Other factors impacting ammonia slip are the amount of sulfur in the fuel, the water and oxygen content, and the exhaust temperature. Thus, a proper and efficient operation of the SCR control system will further minimize ammonia emissions. The D.E.C. Marine AB SCR system design is based on an algorithm that determines urea injection according to engine load and other operational factors. The system also includes a NO_x exhaust monitor that cycles through the six SCR units. The cycle time, including the necessary zero and spanning, is one measurement per engine per hour. This measurement essentially verifies the load-based algorithm and adjusts it if necessary.[2]

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[1] Holmström, Per, D.E.C. Marine AB. [Letter to K. Craik, Shell]. October 9, 2008.

[2] Ibid. footnote 1.

The D.E.C. Marine AB system controls the ammonia slip through routine measurement of the NO_x emissions and adjusts the urea injection rate to match the conversion needs. The operation of this feedback system is verified during initial stack tests and system certification.[3]

Because sulfur in the fuel can lead to SO_2 to SO_3 conversion (typically on the order of one percent), the presence of SO_3 in the exhaust stream can lead to the formation of ammonium bisulfate and ammonium sulfate particles (aerosols). The formation of in-stack sulfate can be minimized by limiting the sulfur in the fuel and limiting the ammonia slip to three to five ppm for high sulfur fuels and less than 10 ppm for low sulfur fuels. For the *Discoverer's* Caterpillar D399s, which will be fuelled with ultra-low sulfur diesel (less than 15 ppm) and which will be equipped with oxidation catalysts, D.E.C. Marine AB believes that the ammonia exhaust emissions will be much less than 10 ppm and close to zero.[4] Thus, there is nearly no SO_3 or ammonia emitted and available for conversion to aerosols.

2.3 Emergency Generator (FD-8)

The *Discoverer* will have one 130-hp emergency generator for use in powering the basic drillship utilities which include domestic and worker safety devices and excludes all drilling equipment. There are no planned uses of the emergency generator except for weekly exercising which involves operation for approximately 20 minutes at loads up to capacity.[5] The seasonal emissions from this weekly 20-minute exercise are estimated at 0.016 ton NO_x, which is 0.03 percent of total *Discoverer* annual NO_x emissions. Since these emissions are small they are grouped with the generator emissions for impact evaluation.

2.4 Propulsion Engine (FD-7)

The *Discoverer* propulsion engine will be shut down prior to placement of the first anchor and turned back on only after removal of the final anchor, so it will have no emissions during the time the drillship is a stationary source.

2.5 MLC Air Compressors (FD-9, 10, and 11) and HPU Units (FD-12 and 13)

The remainder of the diesel engines are used only occasionally for specialized and intermittent tasks. The MLC air compressors (FD-9, 10, and 11) and hydraulic power units HPU (FD-12 and 13) are used for drilling the MCLs, which is the initial drilling activity, for about one week per well. These engines would be operated between 50 and 100 percent capacity during the week needed to evacuate the MLC. Shell requests ORRs of the equivalent of 48 days operation at capacity per season per group for these two source groups. The air compressors are to be new,

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[3] Liljegren, Karin, D.E.C. Marine AB. [Communications with R. Steen, Air Sciences Inc.]. January 28, 2009.

[4] Liljegren, Karin, D.E.C. Marine AB. [Communications with K. Craik, Shell]. January 6, 2009.

[5] Wright, Alistair, Chief Engineer, Frontier *Discoverer*. [Communication with A. Wilson, Frontier Drilling]. January 21, 2009.

Tier 3 engines with no add-on emission controls, while the HPUs are existing engines with catalytic diesel particulate filters (CDPF) for control of oxidizable emissions (volatile organics, carbon monoxide, and hydrocarbon particulate matter).

2.6 Cranes (FD-14 and 15)

The two cranes are mounted on and rotate on pedestals as shown on Figure 2-1 and the engines are mounted on the pedestal with the rotating crane. These are used very intermittently to move materials around the deck and to on-load supplies from the resupply ship. Their operating levels are highly variable depending on the load being moved. There is an ORR limiting the combined operation of the cranes to the equivalent of capacity operation for 38 percent of the season, to be demonstrated through tracking of fuel consumption for the purpose of limiting the long-term (seasonal) impacts. The crane engines have CDPFs for control of organic particulate matter, carbon monoxide, and volatile organics.

2.7 Cementing Units (FD-16, 17, and 18)

The three cementing units are used intermittently when drilling is interrupted for forcing a liquid slurry of cement and additives down the casing and into the annular space between the casing and the wall of the borehole when the drill pipe is pulled out of the hole, or for P&A’ing wells. The cement units are also used intermittently as high pressure pumps for hydrostatically testing various well equipment and drilling components such as the wellhead connections, the blowout preventer, and other connections. Thus, there will be no drilling and the generators will be operating only at low loads when cementing occurs. This decrease in generator emissions is not taken into account in the impact analysis herein. Shell requests an ORR of the equivalent of capacity operation for 30 percent of the day for the three cementing unit engines combined, to be demonstrated through tracking of fuel consumption. The cementing units are equipped with CDPFs for control of volatile organics, carbon monoxide, and organic particulate matter.

2.8 Logging Units (FD-19 and 20)

The two logging units are used to gather information from each well when the drill stem is removed, and will operate only when the cementing units are not used and the prime movers are operating at a low load. The logging units operate at variable and unpredictable loads. The cementing units are used as a substitute for the logging units in the impact analysis and the logging units are to be include with the cementing units’ ORR since the logging units are smaller and produce less emissions per unit time than the cementing units and operate no more than the equivalent of capacity for 30 percent of any one day. In other words, the daily fuel consumption restriction on the cementing units is to include use of the logging units. The logging units also have CDPFs for control of volatile organics, carbon monoxide, and organic particulate matter.

Table 2-1: Discoverer and Associated Vessels Emission Units with Maximum Hourly Emissions That Could Occur Simultaneously

		Rating		Maximum Fuel Consumption (MMBtu/hr) [1]	Maximum Emissions (lb/hr) [1] PM_{10}	$PM_{2.5}$	NO_x	SO_2	CO	VOC	Lead
Frontier Discoverer											
FD-1	Generator Engine	1,325	hp	7.7	0.22	0.22	0.87	1.23E-02	0.31	0.04	2.24E-04
FD-2	Generator Engine	1,325	hp	7.7	0.22	0.22	0.87	1.23E-02	0.31	0.04	2.24E-04
FD-3	Generator Engine	1,325	hp	7.7	0.22	0.22	0.87	1.23E-02	0.31	0.04	2.24E-04
FD-4	Generator Engine	1,325	hp	7.7	0.22	0.22	0.87	1.23E-02	0.31	0.04	2.24E-04
FD-5	Generator Engine	1,325	hp	7.7	0.22	0.22	0.87	1.23E-02	0.31	0.04	2.24E-04
FD-6	Generator Engine	1,325	hp	7.7	0.22	0.22	0.87	1.23E-02	0.31	0.04	2.24E-04
FD-7	Propulsion Engine	7,200	hp	0.0	0.00	0.00	0.00	0.00E+00	0.00	0.00	0.00E+00
FD-8	Em. Generator	131	hp	0.3	0.09	0.09	1.35	4.88E-04	0.29	0.10	8.86E-06
FD-9	MLC Compressor	540	hp	3.8	0.18	0.18	3.55	6.03E-03	3.11	1.20	1.10E-04
FD-10	MLC Compressor	540	hp	3.8	0.18	0.18	3.55	6.03E-03	3.11	1.20	1.10E-04
FD-11	MLC Compressor	540	hp	0.0	0.00	0.00	0.00	0.00E+00	0.00	0.00	0.00E+00
FD-12	HPU Engine	250	hp	1.8	0.10	0.10	5.41	2.79E-03	0.33	0.11	5.08E-05
FD-13	HPU Engine	250	hp	1.8	0.10	0.10	5.41	2.79E-03	0.33	0.11	5.08E-05
FD-14	Port Deck Crane	365	hp	2.6	0.12	0.12	11.27	4.08E-03	0.49	0.16	7.41E-05
FD-15	Starbd Deck Crane	365	hp	2.6	0.12	0.12	11.27	4.08E-03	0.49	0.16	7.41E-05
FD-16	Cementing Unit	335	hp	2.3	0.14	0.14	7.25	3.74E-03	0.44	0.15	6.80E-05
FD-17	Cementing Unit	335	hp	2.3	0.14	0.14	7.25	3.74E-03	0.44	0.15	6.80E-05
FD-18	Cementing Unit	147	hp	1.0	0.06	0.06	3.18	1.64E-03	0.19	0.07	2.98E-05
FD-19	Logging Winch[2]	128	hp	0.0	0.00	0.00	0.00	0.00E+00	0.00	0.00	0.00E+00
FD-20	Logging Winch[2]	36	kW	0.0	0.00	0.00	0.00	0.00E+00	0.00	0.00	0.00E+00
FD-21	Heat Boiler	7.97	MMBtu/hr	8.0	0.19	0.19	1.60	1.27E-02	0.62	0.01	5.39E-10
FD-22	Heat Boiler	7.97	MMBtu/hr	8.0	0.19	0.19	1.60	1.27E-02	0.62	0.01	5.39E-10
FD-23	Incinerator	276	lb/hr		0.97	0.97	0.41	3.45E-01	0.14		
	Total while drilling			84.4	3.91	3.91	68.33	0.48	12.46	3.69	1.98E-03

			Maximum Fuel Consumption (MMBtu/hr) [1]	Maximum Emissions (lb/hr) [1] PM_{10}	$PM_{2.5}$	NO_x	SO_2	CO	VOC	Lead
Associated Fleets										
Ice Management Fleet - Generic										
Diesel Engines			321.7	32.17	32.17	1,029.51	65.00	273.46	26.35	9.33E-03
Incinerators	2-154	lb/hr		1.08	1.08	0.46	0.39	0.15		
Total Ice Management Fleet			321.7	33.25	33.25	1,029.97	65.38	273.62	26.35	9.33E-03
Resupply Vessel - Generic			2.0	0.63	0.63	9.01	0.41	1.94	0.65	5.93E-05
OSR Fleet			17.5	5.42	5.42	61.96	3.53	16.60	5.57	5.07E-04
		Total All Fleet	341.2	39.30	39.30	1,100.95	69.32	292.16	32.56	9.90E-03
		Total All	425.6	43.21	43.21	1,169.27	69.80	304.62	36.25	1.19E-02

[1] All emissions are shown as the maximum 1-hour value.

[2] Logging winches cannot operate simultaneously with cementing units.

Table 2-2: Discoverer and Associated Vessels Emission Units with Annual Emissions

		Rating		Maximum Fuel Consumption (MMBtu/yr)	PM_{10}	$PM_{2.5}$	NO_x	SO_2	CO	VOC	Lead	HAPs
					Maximum Emissions (ton/yr)							
Frontier Discoverer												
FD-1	Generator Engine	1,325	hp	31,082	0.45	0.45	1.76	2.48E-02	0.63	0.08	4.51E-04	0.02
FD-2	Generator Engine	1,325	hp	31,082	0.45	0.45	1.76	2.48E-02	0.63	0.08	4.51E-04	0.02
FD-3	Generator Engine	1,325	hp	31,082	0.45	0.45	1.76	2.48E-02	0.63	0.08	4.51E-04	0.02
FD-4	Generator Engine	1,325	hp	31,082	0.45	0.45	1.76	2.48E-02	0.63	0.08	4.51E-04	0.02
FD-5	Generator Engine	1,325	hp	31,082	0.45	0.45	1.76	2.48E-02	0.63	0.08	4.51E-04	0.02
FD-6	Generator Engine	1,325	hp	31,082	0.45	0.45	1.76	2.48E-02	0.63	0.08	4.51E-04	0.02
FD-7	Propulsion Engine	7,200	hp	0	0.00	0.00	0.00	0.00E+00	0.00	0.00	0.00E+00	0.00
FD-8	Em Generator	131	hp	7	0.00	0.00	0.02	5.85E-06	0.00	0.00	1.06E-07	0.00
FD-9	MLC Compressor	540	hp	4,355	0.10	0.10	2.05	3.47E-03	1.79	0.69	6.31E-05	0.01
FD-10	MLC Compressor	540	hp	4,355	0.10	0.10	2.05	3.47E-03	1.79	0.69	6.31E-05	0.01
FD-11	MLC Compressor	540	hp	0	0.00	0.00	0.00	0.00E+00	0.00	0.00	0.00E+00	0.00
FD-12	HPU Engine	250	hp	2,016	0.06	0.06	3.11	1.61E-03	0.19	0.06	2.92E-05	0.00
FD-13	HPU Engine	250	hp	2,016	0.06	0.06	3.11	1.61E-03	0.19	0.06	2.92E-05	0.00
FD-14	Port Deck Crane	365	hp	3,915	0.09	0.09	8.63	3.12E-03	0.37	0.12	5.68E-05	0.00
FD-15	Starbd Deck Crane	365	hp	3,915	0.09	0.09	8.63	3.12E-03	0.37	0.12	5.68E-05	0.00
FD-16	Cementing Unit	335	hp	2,837	0.08	0.08	4.38	2.26E-03	0.27	0.09	4.11E-05	0.00
FD-17	Cementing Unit	335	hp	2,837	0.08	0.08	4.38	2.26E-03	0.27	0.09	4.11E-05	0.00
FD-18	Cementing Unit	147	hp	1,245	0.04	0.04	1.92	9.93E-04	0.12	0.04	1.80E-05	0.00
FD-19	Logging Winch[1]	128	hp	0	0.00	0.00	0.00	0.00E+00	0.00	0.00	0.00E+00	0.00
FD-20	Logging Winch[1]	36	kW	0	0.00	0.00	0.00	0.00E+00	0.00	0.00	0.00E+00	0.00
FD-21	Heat Boiler	7.97	MMBtu/hr	32,135	0.38	0.38	3.23	2.56E-02	1.24	0.02	1.09E-09	0.00
FD-22	Heat Boiler	7.97	MMBtu/hr	32,135	0.38	0.38	3.23	2.56E-02	1.24	0.02	1.09E-09	0.00
FD-23	Incinerator	276	lb/hr		1.95	1.95	0.83	6.96E-01	0.28			
	Total while drilling			278,255	6.10	6.10	56.14	0.92	11.89	2.53	3.10E-03	0.15

Associated Fleets	Maximum Fuel Consumption (MMBtu/yr)	Fuel Use gal/yr	PM_{10}	$PM_{2.5}$	NO_x	SO_2	CO	VOC	Lead	HAPs
			Maximum Emissions (ton/yr)							
Ice Management Fleet - Generic										
Diesel Engines	492,928	3,703,499	25	25	789	50	209	20	7.15E-03	0.96
Incinerators			0.21	0.21	0.09	0.07	0.03			
Total Ice Management Fleet	492,928	3,703,499	25	25	789	50	210	20	7.15E-03	0.96
Resupply Vessel - Generic	196.22	1474	0.03	0.03	0.43	0.02	0.09	0.03	2.85E-06	0.00
OSR Fleet	23,483	176,435	4	4	42	2	11	4	3.41E-04	0.05
Total All Fleet	516,608	3,881,408	29	29	831	52	221	24	7.49E-03	1.01
Total All	794,863	5,972,012	35	35	887	53	233	26	1.06E-02	1.16

1 Logging winch emissions are included with cementing units.

Table 2-3: Proposed Owner-Requested Restrictions

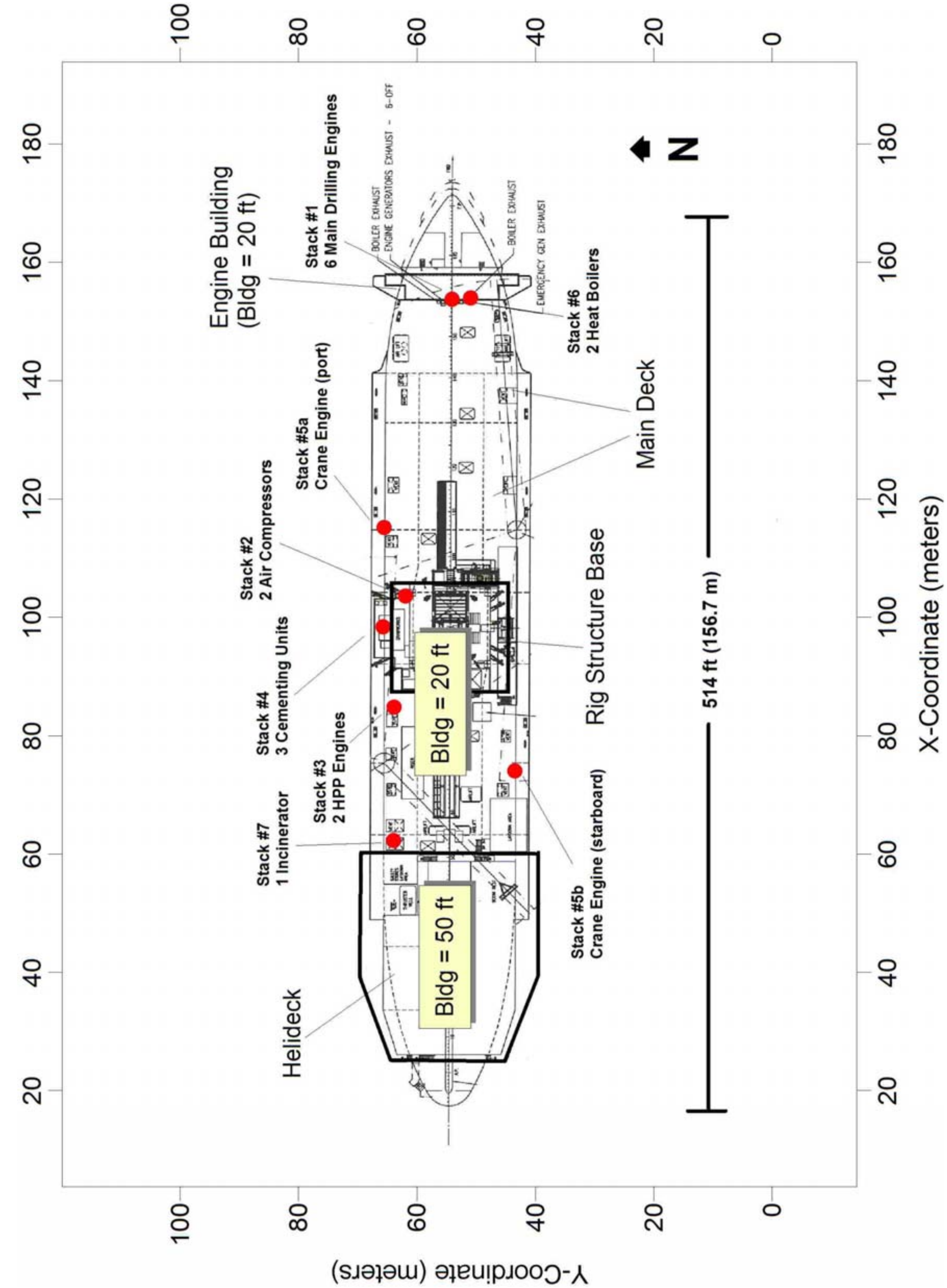
Compliance Condition	Restriction		How Calculated			How Documented
Operational Restrictions						
Season maximum drilling duration	168	days/season	168 days/season x 24 hr/day =	4,032	hrs	First anchoring attached to last anchor removed, by clock.
Drill site maximum drilling duration	84	days/hole	84 days/season x 24 hr/day =	2,016	hrs	First anchoring attached to last anchor removed, by clock.
Minimum distance between drill sites per drilling season	1,000	meters				Site center to site center, GPS.
MLC compressors maximum use per drilling season	48	days/season	48 day/season x 24 hr/day x 2 engines x 540 hp/engine x 0.007 MMBtu/hp-hr x 7.5 gal/MMBtu=	65,434	gal/ season	Demonstrated using fuel consumption – dipstick on the combined MLC compressor consumption at day fuel tank.
HPUs maximum use per season	48	days/season	48 day/season x 24 hr/day x 2 engines x 250 hp/engine x 0.007 MMBtu/hp-hr x 7.5 gal/MMBtu=	30,293	gal/ season	Demonstrated using fuel consumption – dipstick on the combined HPU consumption at day fuel tank.
Generator combined production maximum	80%		80%x 6 engines x 1325 hp x kW/1.340hp=	4,746	kW	Demonstrated by power meter – combined.
Cementing & Logging units combined maximum	30%	(of cementing)	30% x (335 hp x 2 engines +147hp) x 0.007 MMBtu/hp-hr x 24 hr/day x 7.5 gal/MMBtu =	309	gal/ day	Demonstrated using fuel consumption – dipstick on the combined cementing/logging consumption at day fuel tank.
Crane units combined maximum	58,824	gal/season	Max Fuel Consumption			Demonstrated using fuel consumption – dipstick on the combined crane consumption at day fuel tank.
Sulfur content on all stationary source engines on drilling vessel	0.0015%	by weight				Supplier documentation.
Sulfur content on all ships except the *Discoverer*	0.19%	by weight				Supplier documentation.
Ice management fleet fuel restriction while < 25 miles from drill site	3,703,499	gal/season	Fuel Consumption			Demonstrated using fuel purchase records.

Table 2-4: Proposed BACT Control Device Effectiveness

Compliance Condition	Restriction		Comments		Reference
Control Device Effectiveness					
Generator SCR NO_x control effectiveness	0.5	g/kW-hr	50-100% of capacity	CEM	D.E.C. Marine AB letter, October 9, 2008, initial stack test and CEM.
Generator Oxidation Catalyst CO reduction efficiency	80%				D.E.C. Marine AB letter, October 9, 2008, and initial stack test.
Generator Oxidation Catalyst VOC, HAPs, Formaldehyde reduction efficiency	70%				D.E.C. Marine AB letter, October 9, 2008.
Generator Oxidation Catalyst PM_{10} reduction efficiency	50%				D.E.C. Marine AB email, February 9, 2009.
Small engines (other than Tier 3 engines) Catalytic Diesel Particulate Filter (CDPF) CO, VOC, HAPs, Formaldehyde reduction efficiency	80%				CleanAIR Systems PERMIT™ Filter Manual. (Manual claims 85%).
Small engines CDPF PM_{10} reduction efficiency	85%				California Air Resource Board, Currently Verified, January 2009, CleanAIR Systems PERMIT™.

Figure 2-1: Photograph of the Discoverer

Figure 2-2: Layout of Emission Units on the Discoverer



2.9 Heaters/Boilers (FD-21 and 22)

The *Discoverer* has two diesel-fuelled boilers for providing heat for domestic and work space heating purposes, one for normal operation and the second as a backup although there could be times when both would operate. For impact analysis both are assumed to operate simultaneously at capacity and continuously.

2.10 Waste Incinerator (FD-23)

Domestic and other non-hazardous materials are to be incinerated as needed. This man-camp style incinerator is a two-stage, batch-charged unit capable of burning 125 kg/hr of solid trash or 1,000 lb of liquid sewage per day.[6] Its incineration capacity is limited to 3 MMBtu/hr (850 kW) of heat. Its use rate is uncertain and batch size is unknown; so, its emissions are estimated assuming rated capacity use (125 kg/hr) for 24 hours per day and 168 days per year.

2.11 Diesel Fuel Tanks

The *Discoverer* fuel will consist exclusively of diesel which has a very low vapor pressure so the tanks will have negligible vent emissions and are not listed as separate sources, but they are to be tracked in the air permit and are listed in Table 2-5 for this purpose.

Table 2-5: Discoverer Diesel Fuel Tanks

EPA Source ID	*Discoverer* ID	Tank capacity (m^3)
FD-24	21P	538
FD-25	29P	267
FD-26	29S	267
FD-27	21S	179
FD-28	22S	150
FD-29	23S	150
FD-30	24S	135

2.12 Ice Management and Anchor Handling Fleet

The ice management and anchor handling fleet is expected to consist of two leased ships: an icebreaker and an anchor handler / ice management ship. The purpose of this fleet will be to manage the ice, which involves deflecting or in extreme cases breaking up any ice floes that could impact the *Discoverer* when it is drilling, and to handle the *Discoverer* anchors during connection to and separation from the sea floor. The ice floe frequency and intensity is unpredictable and could range from no ice to ice sufficiently dense that the fleet has insufficient capacity and the

[6] TeamTec Incinerators. *Type GS 500C specifications.* Fax February 19, 2007.

Discoverer would need to disconnect from its anchors and move off site. The 2003 – 2005 statistics on ice at the Sivulliq drill site in the Beaufort Sea show 15 percent frequency of ice at the drill site that would need to be fragmented and a 23 percent frequency of ice within 30 miles of the drill site.[7] For the remainder of the time the ice management and anchor handling fleet would be either downwind of the *Discoverer* or beyond the 25-mile radius from the *Discoverer* in a warm stack mode (anchored and occupied). For a conservative estimate of the possible need for ice management, the sum of these two or 38 percent frequency is used. The Chukchi Sea is expected to have less ice, so this 38 percent frequency should represent a high-side frequency for the Chukchi Sea.

When there is ice present at the drill site, ice disturbance will be limited to the minimum needed to permit drilling to continue. The most likely ice to be encountered will be first-year ice, and the ice management ships will be tasked to churn this up so that it will flow easily around and past the *Discoverer* without building up in front of it. This type of ice is fragmented by a continually moving icebreaker (in the extreme case, with thicker (up to 2-meter thick) ice, a rapidly (7 kts[8]) moving icebreaker) moving back and forth across the drift line, directly up-drift of the *Discoverer* and making sharp turns at both ends.[9] The primary driver of the ice floe is the wind, so the ice management ships are upwind of the *Discoverer* when managing the ice. The Shell ice management expert provides a description of the location of the ice management ships during the breaking of the one-year ice.[10] The icebreaker is positioned from 3 miles (4.8 km) to 12 miles (19 km) upwind on the drift line and the anchor handler will be located from the anchor buoy pattern to 6 miles (9.6 km) up-drift from the *Discoverer*. In the extreme case of thick ice, the width of the icebreaker swath will be about 3 miles (4.8 km) to either side of the drift line and the anchor handler will be moving laterally 1.5 miles (2.4 km) to either side of the drift line. (The actual vessel distances will be determined by the ice floe speed, size, thickness, and character, and wind forecast.) With this travel pattern, the ice management ships would spend more time and emit more near the turn-around ends of the cross-wind pattern, but for this analysis, and to be conservative, the emissions are assumed to be spread uniformly in the cross-wind direction. This source configuration for modeling purposes is shown on Figure 2-3. Although 2-meter thick first-year ice is not expected, it might occur and the ice management fleet would be moving at near full speed to fragment this ice. This is considered the case of highest emissions and impacts.

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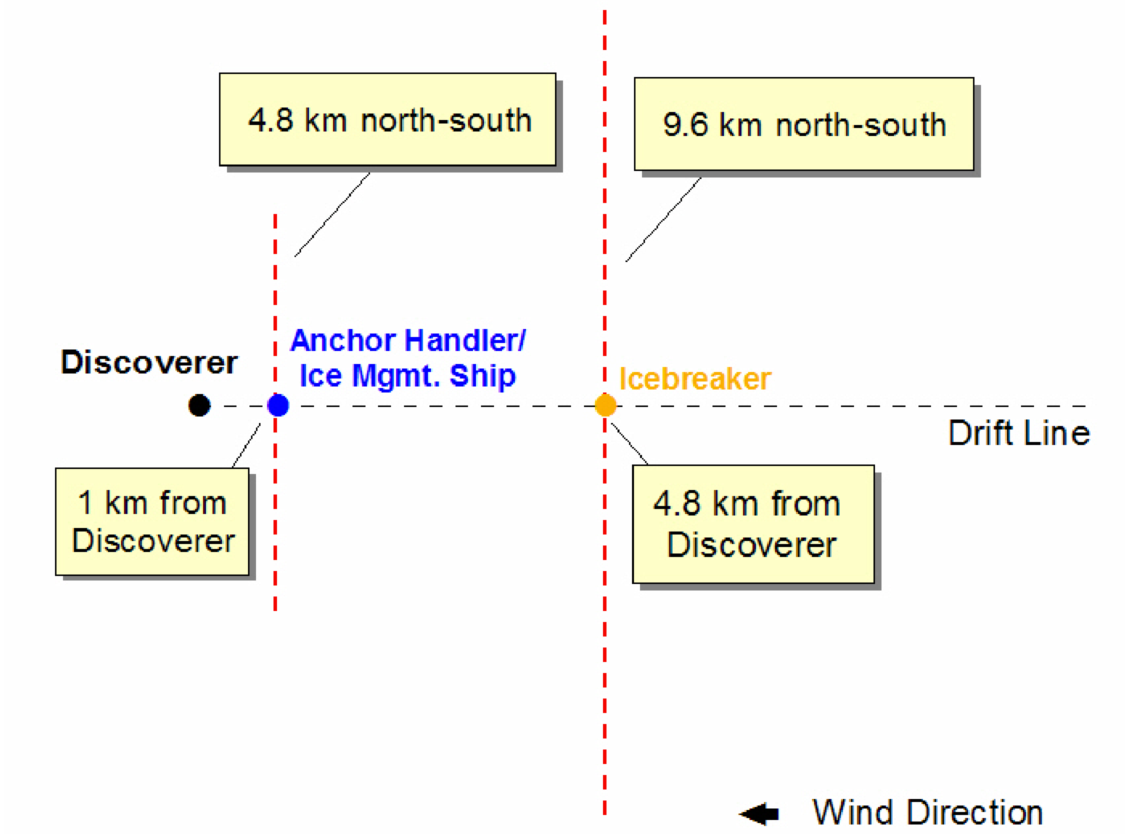
[7] Craik, Keith, Arctic Wells Advisor, Shell International Exploration and Production Inc. [Communication with R. Steen, Air Sciences Inc.]. January 19, 2009.

[8] Craik, Keith, Arctic Wells Advisor, Shell International Exploration and Production Inc. [Communication with R. Steen, Air Sciences Inc.]. January 13, 2009.

[9] Craik, Keith, Arctic Wells Advisor, Shell International Exploration and Production Inc. [Communication with R. Steen, Air Sciences Inc.]. February 10, 2009.

[10] Ibid. footnote 8.

Figure 2-3: Ice management and anchor handling ships locations for breaking of one-year ice



Occasionally there may be multi-year ice ridges which are expected to be broken at a much slower speed than used for first-year ice. Multi-year ice may be broken by riding up onto the ice so that the weight of the icebreaker on top of the ice breaks it. Although this is another emission scenario, the first-year ice is most common and is most efficiently broken at continuous high speed[11] which involves the highest continuous power production and represents the highest emissions. Occasionally there can be ice build-up at the bow of the *Discoverer* that needs a nudge to slide past. In this event the anchor handler will pass close to the *Discoverer* bow and dislodge this ice with its propeller wash, an event that could take up to an hour. Since this is such a short activity, at low power, and operating side to side of the bow (rather than in front of), its emissions will be low and the impact will be small. The impact from this activity is not separately modeled.

The emission units of the icebreaker and anchor handler consist of the diesel engines for propulsion, general purpose generators and heaters, and an incinerator as listed in Appendix B, Page Fleet-1. Short-term emissions from the ice management ships are calculated at maximum use of the emission units, which is 80 percent of capacity for the propulsion engines,[12] and 100

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[11] Ibid. footnote 8.

[12] U.S. EPA. *Alaska Outer Continental Shelf Air Quality Control Minor Permit Approval To Construct. Permit Number: R100CS-AK-07-02 (Revised). Kulluk Permit – Condition 9.2 (a) (i).* June 18, 2008.

percent of capacity for the remaining emission units. The long-term emissions are calculated with these ships in this highest impact position for 38 percent of the season.

The ice management and anchor handling fleet is expected to consist of two ships, an icebreaker and an ice-class anchor handler. The ice management fleet is leased from year to year and is likely to change from year to year. Thus, Shell requests that the permit allow for a generic ice management fleet. Furthermore, the fleet could consist of more or less than two ships depending on availability of ships and ice conditions. There are only a limited number of eligible ships at this time represented by the ice management ships listed in Table 2-6. The impacts of the generic fleet are defined herein by the ship with the lowest plume rise combined with a permit-restricted NO_x emission limit (converted to a fuel limit as listed in Table 2-4). NO_x is selected because the restriction is developed to limit NO_x impacts from the ice management and anchor handling fleet. The propulsion engine exhaust stacks of the eight ships listed below were modeled for plume rise (Appendix B, Page *Discoverer* 4), the Vladimir Ignatjuk plumes were the lowest (Table 5.4), so the impact analysis described in Section 6 of this report are based on the permit limited emissions from this stack with lowest plume rise. Impacts from all other ships emitting at the same rate will have lower impacts. The defined NO_x emission limit is established from the pair of ice management ships combined by calculating the daily and annual maximum energy consumption of the current pair of ice management ships and converting this to emissions using manufacturer emission factors. All other combinations of ice management ships will be expected to meet this NO_x emission limit calculated using their own unique emission factors.

Table 2-6: Eligible Ice Management Ships

Ship Name and Owner
Vladimir Ignatjuk, Murmansk Shipping
Talagy, Smit
Kapitan Dranitsyn, Murmansk Shipping
Odin, Viking
Nordica / Fennica, Finstaship
Tor, Viking
Balder, Viking
Vidor, Viking

The currently planned fleet consists of the Vladimir Ignatjuk as the icebreaker and the Nordica as the anchor handler/ice management ship. For purposes of the impact evaluation herein, their daily energy consumption (MMBtu/hr) is estimated from maximum operation of all emission units of these two ships. Seasonal emissions are estimated from these short-term values by multiplying the short-term values by 38 percent of the 168 days of the maximum season. The limits are to be tracked in the form of a combined annual fuel consumption limit using highest emission factor (lb/gallon) per group of engines based on stack testing of a typical propulsion engine and manufacturer emission factors for the smaller sources.

The anchor-handling involves placing the *Discoverer* anchors on the seabed in preparation for drilling, and retrieving the anchors when the *Discoverer* is being moved off the well. Placement involves backing the handler up to the *Discoverer* under low power, connecting to the anchor line, reeling out the line, and setting the anchor at approximately 1,000 meters distance, then moving to another anchor opposite the first. Setting of each anchor consumes about 30 minutes and the entire process consumes no more than 18 hours. Anchor handler propulsion power during these 18 hours is either low or at idle since it is precision work setting anchors, spooling-out lines, and tensioning lines. Since much of this activity takes place while the *Discoverer* is a stationary source, the anchor management emissions are already included in the ice management and anchor handler fleet emission inventory totals.

Regarding possible impacts of this activity, since the anchor placement and retrieval occurs when all drilling, cementing, and logging activities are shut down, occurs while under low power of the anchor handler, and is spread over a two km diameter circle, the short-term (hourly and daily) impacts will not occur simultaneously with the larger *Discoverer* impacts. Emissions are much higher during drilling and when the two ice management ships are managing ice, and thus the anchor placement activity will not be a condition causing or contributing to highest impact.

2.13 Oil Spill Response (OSR) Ships

The OSR fleet in the Chukchi is expected to consist of one offshore management/skimmer ship (currently the Nanuq), and three 34-foot boats. Two of the 34-foot boats will be used to tow containment booms while the third will act as a backup, for crew changes, and for re-fueling. The Nanuq is expected to be used only in the unplanned and unlikely event of an oil discharge to the water and normally will remain within about five km of the drillship and downwind, but at least two km away for safety purposes. The small craft will remain on the deck of the management vessel and will only be in the water for training, drills, and response events. The OSR fleet will have on-water drills at a maximum frequency of once per day, which will consist of an 8 hours exercise. The exercise will normally consist of two 34-foot boats towing an open apex boom diverting a water stream back to the Nanuq. The Nanuq will have skimmers deployed and be simulating the recovery of oil downstream of the open apex. During this exercise, the small craft as well as the Nanuq will be moving at approximately 0.5 kts. With this slow speed and using the approximation that vehicle power is related to the square of the vehicle velocity,[13] the Nanuq's propulsion power is estimated to be less than 10 percent from one engine. The OSR Nanuq pilot estimates that the two small boats with two engines each will be at approximately 50 percent.[14]

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[13] One form of Bernoulli's Equation: $P = k * (velocity)^2$. With a vehicle maximum of 14 kts, the power to move the ship at 1 kt is 1/196 of full power or less than 1 percent of full power. Terminel, Michael, Alaska Operations Edison Chouest Offshore. [Communications with R. Steen, Air Sciences Inc.]. February12, 2009.

[14] Seltz, Richard H., Alaska Simops Coordinator. [Communication with R. Steen, Air Sciences Inc.]. February 12, 2009.

There will be two other vessels associated with the OSR fleet. One tanker will normally reside 25 miles from the fleet. On occasion the tanker will come in for re-fueling and training purposes for short periods of time. The tanker's function is to store oil and water from the Nanuq as it becomes full from cleanup operations. The Tug/Endeavor Barge will reside near the Chukchi coast. Its task is to perform near-shore clean up in the event oil goes in that direction. This ship combination will not come out to the drill site. Thus its emissions are not considered with the offshore OSR fleet. The OSR fleet will perform daily training when weather and seas permit, but will stay in the same area as the *Discoverer*, 2 or more km downwind. The emissions from the training exercises of this OSR fleet are based on daily training, eight hours per day, for the 168 days season and the emission factors are taken from the Kulluk permit which represent the highest emission factors for the source category. For modeling purposes, the emissions are spread over a two km distance, two km downwind of the *Discoverer*.

2.14 Resupply Ship

The *Discoverer* is expected to be provisioned for the first few wells at the beginning of the season, and will be re-provisioned at intervals of 2 to 4 weeks, for a maximum of 8 re-provisionings. The supply ship is currently expected to be similar to the foreign-flagged Jim Kilabuk, if the drillship is resupplied out of Canada, or a similarly sized Jones Act compliance vessel, if resupplied out of Alaska. There will be no need for it to be within 25 miles of the *Discoverer* except for the time needed to approach, deliver, and leave the area. If it makes a delivery, it will attach to the *Discoverer* for less than 12 hours during which time one of its 292-hp generators will be operating at some power level, assumed for this impact analysis to be capacity, for ship utility powering. Its generator emissions while attached to the *Discoverer* are estimated (Tables 2-1 and 2-2) and its impacts are included in the impact analysis.

2.15 Fuel Used

Regarding the fuel used, the fleets will voluntarily use diesel fuel with sulfur content of 0.19 percent or less to limit SO_2 emissions from the fleet, and, as BACT, the *Discoverer* will use ultra-low sulfur (15 ppm) fuel to minimize the SO_2 emissions from the *Discoverer*. These are ORRs. Currently the ultra-low sulfur fuel is not available on the North Slope and, if needed now, would be barged from the northwest, from north through Canada, or purchased in the Far East. These fuel qualities are incorporated in the emission and impact assessments. No ultra-low sulfur fuel has been purchased by Shell for Alaska use so density and heat content can only be estimated from fuel recently purchased for North Slope use[15], [16]. These values are incorporated in the emission calculations of Appendix A and B.

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[15] Skandinaviska Raffinaderi AB, SCANRAFF. *Vladimir Ignatjuk Certificate of Quality*. September 19, 2004.

[16] Keiser, Ronald, Domestic Fuels Manager, Shell Marine Products (US) Company. [Communication with C. Tengco, Shell]. January 26, 2009.

2.16 Residential, Commercial, and Industrial Growth

The indirect activities associated with the *Discoverer* exploration activities are likely to include support facilities in Wainwright or Barrow, with possible minor activities in Deadhorse and Kotzebue. The facilities could include storage facilities and aircraft hangers. Crew accommodations are expected to be in existing hotels but could include some temporary trailer camps. Equipment change-out is expected to be by existing commercial means (airlines). Communications would be through existing communications center networks.[17]

2.17 Emissions for Purposes of Modeling

For purposes of dispersion modeling, the short-term PM and NO_x emissions represent maximum 24-hour values because the impact standards are averaged over 24 hours or longer. While Page 1 of Appendix A (*Discoverer* Emissions) contains the maximum hourly emissions, Page 2 emissions take into account any daily ORRs (limitations) in daily use. The Page 2 emissions are carried over to the modeling emission inputs. The CO and SO_2 emissions on Page 2 used in the model are maximum 1-hour values (carried over with no modification from Page 1). Page 3 contains the stack dimensions used in the impact model. Page 4 contains the partial loads emissions and impacts analyses. Pages 5 through 7 contain the source conversion to forms that the model understands. Page 8 is a plan view of the *Discoverer* deck showing locations of the source and is identical to Figure 2-2. Page 9 contains the building dimensions used in the BPIP wake effect analysis. The following Pages 10 through 12 contain the tabulated hourly and annual emissions, including the hazardous air pollutants (HAPs), for inventorying purposes and Pages 13 and 14 contain the emission factors used for all emission units. While the fleet emission summaries are on the *Discoverer* emissions sheets, the fleet emissions, by emission unit, are calculated and displayed on the Fleet Emissions, Pages 1 through 3. For a better understanding of the underlying calculations, it should be noted that values in blue are input values, values in black are calculated values.

The emissions of criteria (NAAQS) and total HAPs pollutants for the *Discoverer* and the associated fleets are calculated and provided in Tables 2-1 and 2-2. These emissions are built on maximum emission unit use rates which account for any operational restrictions listed in Table 2-3, and emission factors provided either by stack tests, the manufacturers, or generic EPA factors when manufacturer factors are not available. The data used to construct these emission tables are provided in Appendix B. The ORRs in Table 2-3 will apply to normal exploration drilling and well completion operations and, except for fuel sulfur content, these restrictions are not applied to operations that are undertaken to protect human health, safety, or the environment in response to a well control event that might occur despite Shell having exercised reasonable due care to avoid such an occurrence.

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[17] Pavia, Gene, Principal Consultant,UMIAQ. [Communication with R. Steen, Air Sciences Inc.]. January 22, 2009.

2.18 Emissions and Impacts as a Function of Load

For purposes of estimating emissions and demonstrating that the maximum impacts are due to diesel engines running at maximum, which is 100 percent of capacity for all engines except the propulsion engines and 80 percent for the propulsion engines, the impacts of five of the larger diesel engines are modeled at three loads. Although these engines do not cause the largest local impacts, they are representative of different models of diesels and therefore should be representative of the smaller engines also. These are the engines that have the most complete emissions at partial load data available. Incinerator emissions at various loads are not available in the literature or from the manufacturer. Its anticipated use pattern is to receive occasional batches and to supply heat at design heat rate for short periods of time; so it would emit at capacity rate but for short periods of time.

The propulsion engines for four ice management and anchor handler ships are modeled at three loads: 35, 57, and 80 percent load; and the *Discoverer* generator engines are modeled at 50, 75 and 100 percent load. Each load has a separate emission factor and set of stack parameters, provided in Table 2-7 and Appendix B, Page 4 with references. From this table it is apparent that even though the engines may operate at low loads, it is the emissions and stack parameters of maximum load that causes the highest emissions and impacts. Therefore the impact analysis in Section 6 is based on engines operating at maximum load.

2.19 Other Activities

Tables 2-1 and 2-2 contain all the pollutant emitting activities associated with the project. EPA has asked specifically to address the possibility of emissions from drilling of relief wells, use of diverters, well control events, flares, well testing, fuel tanks, etc.[18]

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[18] EPA Comments, Attachment B, II.B.4.

Table 2-7: NO_x Emissions and Impacts at Three Loads

Load (% of capacity)	Engine	NO_x emissions (g/s normalized)	NO_x impact (ug/m^3)
80	Vladimir Ignatjuk - Wärtsilä / 9ZL	1.000	65.5
57		0.818	45.4
35		0.354	22.4
80	Kapitan Dranitsyn – Sulzer 9ZL40/48	1.000	46.6
57		0.502	24.6
35		0.345	16.7
80	Fennica/Nordica - Wärtsilä / 16V32	1.000	49.2
57		0.690	34.0
35		0.508	25.0
80	Tor Viking II – MaK 8M32C	1.000	44.9
57		0.374	17.8
35		0.189	9.2
100	*Discoverer* – Caterpillar D399	1.000	32.4
75		0.771	30.0
50		0.545	25.4

Table 2-8: PM_{10} Emissions and Impacts at Three Loads

Load (% of capacity)	Engine	PM_{10} emissions (g/s normalized)	PM_{10} impact (ug/m^3)
100	*Discoverer* – Caterpillar D399	1.000	32.4
75		0.533	20.7
50		0.315	14.7

Shell does not plan to flow test wells, flare gas, or store liquid hydrocarbons recovered during well testing during its planned drilling campaign using the *Discoverer*. Therefore, no emissions from flaring or stored crude oil tank vapors are included in Tables 2-1 and 2-2. [19] The only fuel in use on the *Discoverer* and associated fleets will be diesel, which has an extremely low vapor pressure and therefore there will be negligible emissions from vented fuel tanks. Thus, no emissions are included in the emission inventory for these possible source categories.

With respect to relief well emissions, in addition to the fact that any such drilling is an extremely remote contingency, Table 2-1 already includes the relevant emissions information. The only emissions that would be associated with well control events would be emissions produced from drilling the relief well in the very unlikely event that this were necessary to control a blowout. No emissions would be associated with emergency deployment of the ship's Subsea Blowout Preventer (SSBOP). Table 2-1 provides hourly emissions estimates for drilling activities by the *Discoverer* and its associated ships. Those emissions estimates would apply to drilling whether

[19] Craik, Keith, Shell. [Communication with R. Steen, Air Sciences Inc]. February 4, 2009.

the well being drilled is a planned well or a relief well being drilled in response to a well control event. Thus, it is not necessary to revise Table 2-1 because it already incorporates the hourly emission rates during relief well drilling, in the exceedingly unlikely event that such drilling ever occurs.

Table 2-2 provides the estimated annual emissions for the *Discoverer* and its associated ships, based upon operation at the hourly emissions rates for each emissions unit set forth in Table 2-1, in compliance with the ORRs on total days of operation per season in Table 2-3.

Table 2-2 is essentially a specification of allowable emissions for all of the emissions units on or associated with the *Discoverer* under normal operating conditions. Allowable emissions are the maximum emissions allowed under the permit under normal operating conditions – here, the emissions that are allowed under the EPA-enforced ORRs in Table 2-3. See 40 CFR § 52.21(b)(16). EPA's regulations indicate that allowable emissions should not include emissions that would occur only as a result of events outside of standard operating conditions. Appendix W to 40 CFR Part 51, "Guidelines on Air Quality Models" instructs that emissions resulting from malfunctions should not be factored in to allowable emissions.

> *Malfunctions which may result in excess emissions are not considered to be a normal operating condition. They generally should not be considered in determining allowable emissions.*

Emissions from emergency drilling operations, even more so than ordinary malfunctions, are highly unlikely, infrequent events and should not be considered the "normal operating condition" of the drilling operation. Therefore, they should not be separately factored into the allowable emissions under this permit as represented in Table 2-2.

In addition to being consistent with EPA policy, restricting Table 2-2 to only those emissions associated with the ordinary operating conditions under the permit is the best and most accurate approach to conservatively and realistically estimating total annual emissions from these units. It is highly improbable that emissions relating to the potential drilling of an emergency relief well to address a well control event would ever occur. Therefore, Shell would maintain that it is neither informative nor appropriate to include such speculative emissions in this table of estimated "annual" emissions from drilling and associated activities.

Shell drilling plans, protocols, and procedures and the MMS Application for Permit to Drill (APD) detail drilling operation precautions for avoiding blowouts during drilling operations. EPA has previously acknowledged that the odds that a well control event could occur during exploration drilling on the Alaska OCS and that a relief well would then be necessary to bring the well under control are almost 1 in 6,000. The inclusion in Table 2-2 of emissions from drilling activities that might occur only during one drilling operation in several thousand would incorrectly "skew" the data in that table, so as to make it unrepresentative of "annual" emissions and inaccurate for anticipated operations.

Because emissions from drilling a relief well are so unlikely to occur and are not reasonably foreseeable, Shell would further maintain that it is also not appropriate or practical to include such emissions in the air quality modeling for the *Discoverer*. In the highly unlikely event that, at some future time, the *Discoverer's* drilling operations were to cause a violation of a NAAQS or the PSD increment due to emissions produced during emergency relief well drilling at the end of a drilling season, it is acknowledged that EPA would have discretion to take enforcement action against Shell for such a violation under the Agency's policy on "excess emissions" that result from, inter alia, malfunctions. See "State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown," Steven A. Herman, Assistant Administrator for Enforcement and Compliance (September 20, 1999) ("Herman Memorandum"). [20]

[20] This policy was reconfirmed in a memorandum issued by Eric Schaeffer, Director of the Office of Regulatory Enforcement, dated December 5, 2001, which clarified that the policy was intended to be applied prospectively to future SIP approvals. Although these guidance documents are designed to set out the standards under which EPA will approve a SIP, they also provide the most applicable guidance to of EPA's policy regarding excess emissions for all permits, those issued pursuant to a SIP and those issued under federal regulations.

SECTION 3

REGULATORY APPLICABILITY

The *Discoverer* is to be an "exploratory OCS source," under 40 CFR Section 55.2, and will be regulated under 40 CFR Section 55.3 (c). Since it will be drilling beyond the 25-mile Alaska Seaward Boundary, it will be exempt from the Alaska-only requirements (40 CFR Sections 55.4, 55.5, 55.11 and 55.12). Under Section 55.6 (a)(1), an OCS permit application is required, and under Section 55.6 (a)(3) the administrator (EPA Region 10) is instructed to follow the administrative procedures of 40 CFR Section 124, used to issue PSD permits. Section 55.6 (d) requires permitting by the Section 55.13 requirements. Sections 55.8 and 9 address compliance requirements and enforcement. Section 55.10 instructs the EPA to apply operational fees according to Part 71 requirements. Section 55.11 allows for the delegation of the administration of these rules.

From a regulatory perspective, the OCS source is the *Discoverer* and it is regulated only when it is attached to the seabed (Section 55.2, "OCS source"). This stationary source includes any additional ships when physically attached to the *Discoverer* (Section 55.2, "OCS source"). For purposes of this permitting, the source, its emissions, and its emission controls and operational restrictions are described only for the drilling activity, which is defined as the time from placement of the first of eight anchors to removal of or detachment from the last anchor. The *Discoverer's* emissions are not regulated (or defined) while not attached to the seabed.

The "potential emissions" as defined in Section 55.2 are used to determine applicability of Section 55.13 (d), which are the 40 CFR Section 52.21 (PSD) permitting rules and include the emissions from the *Discoverer* and associated fleets when they are within 25 miles of the drill site. The emissions in Tables 2-1 and 2-2 represent the emissions during the time the *Discoverer* is a stationary source and are appropriate for drilling impact modeling. They do not include the minor addition from the *Discoverer* propulsion emissions for the approximate four hours of time to bring the *Discoverer* the final 25 miles to the drill site and move it away (which would add less than one half ton of NO_x emissions). As depicted in the last row of Table 2-2, the *Discoverer* and fleets totals for particulate matter (PM_{10} and $PM_{2.5}$), nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), and volatile organic matter (VOC) exceed the thresholds of applicability (52.21 (b)(1)(i)). Therefore, Section 52.21 rules apply to this source, and it is unnecessary to consider the emissions from the approximate four hours to transport the *Discoverer* within 25 miles to and from the drill site to determine whether the PSD rules are applicable. The PSD rules are applicable.

This application focuses on the permitting requirements under Section 55.13, subsection (c), (d), (e), and (h). The applicability of subsection (d) is determined first, and since it is applicable to the *Discoverer*, the other subsections need not be addressed outside of (d) because they are embedded in the (d) requirements. Section 55.13 (d) requires the *Discoverer* OCS source to address the 40 CFR Section 52.21 major source permitting rules and these rules include:

Section (j) Control Technology Review: This review includes a best available control technology (BACT) review for all regulated NSR pollutants with the potential to be emitted in significant amounts, NSPS applicability and NESHAPs applicability determination. This review is in Section 4 of this application.

Section (k) Source Impact Analysis: This demonstration that the *Discoverer* will not cause or contribute to a violation of NAAQS or PSD increment is included as Section 5 of this application.

Section (m) Air Quality Analysis: This review of baseline concentrations of regulated NSR pollutants with the potential to be emitted in significant amounts is included in Section 6 of this application.

Section (o) Additional Impact Analysis: This impact analysis of impairment to visibility, soils, and vegetation is included in Section 8 of this application.

Section (p) Sources Impacting Federal Class I Areas: Shell claims exemption from this subsection because of the distance from the nearest Class I area. Denali National Park is the nearest Class I area and it is over 600 miles from the source, which is beyond the distance of concern and is not considered further herein.

In the process of addressing the emission control technology, source impact analysis and air quality analysis requirements, the pollutants to be addressed are limited to those that have emissions greater than "significant emission rate" defined in Section 52.21 (b)(23) and the definition of "source" for the purpose of determining "significant emission rate" is not clearly defined. Table 3-1 shows the "Significant Emission Rate" for each pollutant and the corresponding projected emissions both from the *Discoverer* alone and from the *Discoverer* with the associated fleets, each under the proposed operating restrictions in Table 2-3.

Table 3-1: Significant Emission Rates

Pollutant	Significant Emission Rate Threshold [1] (tpy)	*Discoverer* Emission Limit (tpy)	*Discoverer* and Fleet Emission Limit (tpy)
Nitrogen Dioxide (NO_x)	40	56.14	887
Particulate Matter ($PM_{2.5}$)	10	6.10	35
Particulate Matter (PM_{10})	15	6.10	35
Sulfur Dioxide (SO_2)	40	0.92	53
Carbon Monoxide (CO)	100	11.89	233
Volatile Organics	40	2.53	26

[1] 40 CFR Section 52.21 (b)(23)

This application analysis is based on the conservative assumption that significant emission rates could include emissions from the *Discoverer* and its associated fleets. And therefore both a source impact analysis from the *Discoverer* and fleets, and Best Available Control Technology (BACT) analysis for *Discoverer* source units will be performed for NO_x, $PM_{2.5}$, PM_{10}, SO_2, and CO emissions.

Regarding the impact analysis, this application demonstrates that the *Discoverer* will be in compliance with increment and the NAAQS at the Burger Prospect (71° 15′ N, 163° 13′ W), shown on Figure 1-1, which is expected to be its initial operating location. Thereafter, as a portable source, the *Discoverer* is proposing to drill at any of Shell Gulf of Mexico Inc.'s existing leases in the Chukchi Sea, beyond the 25-mile limit without the necessity of further demonstrating compliance with the PSD increment and NAAQS as long as it meets the definition of "portable." Section 52.21 (i)(1)(viii), provides this exemption when a previously permitted source is relocated and its emissions will be temporary, its emissions will not exceed the permit limits at any new location, the emissions will impact no Class I area and will not contribute to any known increment or NAAQS violation, and reasonable notice of relocation is provided to the Administrator. Although not a permitting requirement, Shell also provides a hypothetical worst-case analysis of modeled ambient air quality impacts at the nearest Chukchi shoreline villages that are located closest to a Shell lease, with drilling assumed to occur on that least for the entire season (Section 7.4).

EMISSION CONTROL TECHNOLOGY REVIEW

4.1 Best Available Control Technology (BACT) Overview

Table 3-1 indicates that emissions from the *Discoverer* and its associated support vessels exceed the Significant Emission Rates established for NO_x, PM_{10}, SO_2, and CO. According to 40CFR52.21 (j) (2), a BACT analysis is to be performed on each emission unit on the *Discoverer* that emits these pollutants.

BACT is defined in the PSD regulations as:

> *"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs" [40 CFR 52.21(b)(12)].*

In a 1987 memorandum, EPA provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps described below (from the EPA's Draft New Source Review Workshop Manual, 1990).[21]

1. Identify all available control technologies.
2. Eliminate technically infeasible options.
3. Rank remaining technologies by control effectiveness.
4. Evaluate the most effective control based on a case-by-case consideration of energy, environmental, and economic impacts.
5. Select BACT.

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[21] U.S. EPA. *New Source Review Workshop Manual Prevention of Significant Deterioration and Nonattainment Area Permitting*. Draft October 1990.

Shell applied EPA's top-down methodology to groups of similar emission units on the *Discoverer*. For example, there are six large diesel generators that are identical, so individual BACT analyses are not warranted. Similarly, there are small diesel engines (<500 hp) and diesel fired compressors (540 hp) that are very similar and the BACT determinations for individual units would be redundant.

Table 4-1 identifies the emission unit categories and summarizes the results of Shell's BACT analysis. Additional detail is provided in the following sections.

Table 4-1: Source Categories, Proposed BACT

Source Category	PM_{10}	NO_x	SO_2	CO
Diesel Generators (1,325 hp)	OxyCat	SCR	ULSD	OxyCat
Small Diesel Engines (<500 hp)	CDPF	GCP	ULSD	CDPF
Diesel Compressors (540 hp)	Tier 3	Tier 3	ULSD	Tier 3
Heater/boiler	GCP	GCP	ULSD	GCP
Incinerator	GCP	GCP	ULSD	GCP

SCR selective catalytic reduction
OxyCat oxidation catalyst
CDPF catalytic diesel particulate filter
GCP good combustion practices
Tier 3 EPA Non-Road Engine Tier 3 Emission Standards per 40 CFR 89.112
ULSD Ultra-low sulfur distallate fuel (15 ppm sulfur content)

An OCS exploratory drilling operation is substantially different than the industrial sources typically addressed by the PSD permit process. As a result, we find a number of areas where the typical permit process just doesn't "fit." For example, all of the emission units on the *Discoverer*, except for the MLC compressors, are existing units, purchased and used for many years prior to this application, so BACT is focused on retrofit technologies.

One interpretation of applicable regulations is that the anchor handler vessels and resupply ship are part of the *Discoverer* "stationary source" when they are (however briefly) connected to the *Discoverer*. As part of the stationary source, one might conclude that BACT must be applied to the emission units on these vessels. Shell has not conducted a detailed BACT analysis for these vessels because there is no way implementation of emission controls beyond good operating practices could be cost effective.

- Supply vessels. There are expected to be a maximum of 8 resupply events. When supplies are delivered, the supply vessel would be tied alongside the *Discoverer* for a maximum of 12 hours, for a season maximum of 96 hours, and with only the generator operating. Emission calculations in Appendix A indicated the generator on the supply ship could emit up to 860 lb NO_x and 60 lb PM_{10} during this period. Since this will be a leased vessel, it may only serve the *Discoverer* for one season. Given this low emission rate, the total emissions would be small. It is inconceivable that implementation of additional controls on the supply vessel generator could be cost effective.

- Anchor handler. Setting the anchors is expected to require approximately 18 hours of low speed operation of the anchor handling vessel. Even with the possible drilling of four wells (eight anchor handling events), annual emissions will be small. It is inconceivable that implementation of additional controls on the leased anchor hander vessel, that could be used with the *Discoverer* for only one season, could be cost effective.

4.1.1 NO_x BACT Analyses

Step 1 – Available Control Technologies

There are two sources of nitrogen that when oxidized result in NO_x emissions – nitrogen in the fuel and nitrogen in the combustion air. Oxidation fixation of atmospheric nitrogen is known as thermal NO_x. The production of thermal NO_x is a function of combustion flame temperature.

The available NO_x control technologies for the *Discoverer's* engines, boilers, and incinerator can be characterized by the following two categories: combustion control and post-combustion exhaust treatment. In combustion control, thermal NO_x is reduced by lowering the peak combustion temperature. Post-combustion exhaust treatment relies on the removal of NO_x from the exhaust stream through adsorption or reduction.

Available NO_x control technologies for the *Discoverer's* engines, boilers, and incinerator were determined by searching the EPA RACT/BACT/LAER Clearinghouse (RBLC) and the California Air Resources Board Statewide Best Available Control Technology Clearinghouse (CA-BACT). The search conditions and a summary of the resulting control technologies are provided in Table 4-2. The complete database downloads are provided in Appendix C. For the RBLC, only those determinations made after January 1, 1999, were downloaded because older determinations are typically less stringent.

Table 4-2: Available NO_x Control Technologies

Source Category	Clearinghouse	Search Conditions	Control Technologies
Diesel IC Engines (>500 hp)	RBLC	Process Code = 17.110	None, AC, HIP, ITR, LND, SCR, TIER 2/3, WI
	CA-BACT	I.C. Engines - CI, Non-Emergency (>500 hp)	None, AC, SCR, ITR
Diesel IC Engines (≤500 hp)	RBLC	Process Code = 17.210	None, AC, ITR, LND
	CA-BACT	I.C. Engines - CI, Non-Emergency (≤500 hp)	None, AC, ITR, WI*
Boiler (≤100 MMBtu/hr)	RBLC	Process Code = 13.220	None, LNB, FGR
	CA-BACT	Boilers – Oil Fired (≤100 MMBtu)	No determinations
Incinerator	RBLC	Process Description = Incinerator; Fuel = Solid Waste	None, SNCR
	CA-BACT		No determinations

*Unit was never installed.

CI Compression Ignition.

Process Code Key:

17.110 - Large Internal Combustion Engines (>500 HP); Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

17.210 - Small Internal Combustion Engines (≤500 HP); Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

13.220 - Commercial/Institutional-Size Boilers/Furnaces (≤100 million BTU/H); Distillate Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

Control Technology Key:

AC	Intake Air Cooling
FGR	Flue Gas Recirculation
HIP	High Injection Pressure
ITR	Injection Timing Retard
LNB	Low NO_x Burners
LND	Low NO_x Design
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
TIER 2/3	EPA Non-Road Engine Emission Standards per 40 CFR 89.112
WI	Water Injection
None	No specific technology listed or good combustion practices

Diesel-fueled Reciprocating Engines

The available NO_x combustion control technologies for diesel engines identified in the RBLC and CA-BACT are injection timing retard (ITR), intake air cooling (AC), high injection pressure (HIP), low NO_x design (LND), Tier 2 or 3 level controls, water injection (WI), and good combustion practices. The RBLC and CA-BACT also listed lean burn, air-to-fuel ratio control, turbocharger, clean fuel, and preventative maintenance as part of the NO_x control description. These technologies or work practices are not specific to NO_x reduction and, therefore, are not discussed further.[22]

ITR reduces NO_x emissions in reciprocating engines by delaying the injection of fuel in the engine from when the chamber is at its smallest to a time when the compression chamber is expanding. The larger volume in the compression chamber lowers peak combustion temperature, thus reducing thermal NO_x formation. Lower peak combustion temperature can also be achieved with charge air coolers (AC), common to turbo charged engines, which reduce the intake manifold temperature. The combination of ITR and AC may reduce NO_x by 10 to 50 percent (up to 40 percent from ITR and an additional 10 percent from AC).[23]

Cooling the flame with ITR and/or AC reduces NO_x at the expense of incomplete combustion, resulting in the formation of PM, VOC, and CO emissions and reduced fuel economy.[24] The fuel economy penalty can be reduced by increasing injection pressure. High injection pressure (HIP) can accomplish better fuel atomization which leads to better combustion and reduced PM emissions. ITR also has a negative impact by contamination of lube oil with soot which increases engine wear.[25]

In WI systems, water acts as an inert gas and also absorbs heat in the process of evaporation. Both effects cause a decrease in the peak combustion temperature, thus reducing thermal NO_x formation by up to 50 percent.[26] The main disadvantage of WI is the large amount of extremely pure water required. In general, reduction of NO_x by one percent requires one percent of water in the water-fuel system.[27] In other words, achieving a 50 percent NO_x reduction requires running the engine using a 1:1 mix of water and diesel fuel. Another problem with the introduction of water in the combustion chamber is the potential for liquid droplets to contact the cylinder surface. In this case, there would be an immediate disintegration of the lubrication oil film, damaging the engine. Cold temperature environments (such as the Arctic Ocean) are also problematic for WI systems due to the potential for freezing.

The RBLC also lists low NO_x design (LND) for several engines, but does not describe the actual NO_x combustion control technology. It is assumed that these determinations are referring to specific combustion chamber designs which provide good mixing of fuel and air before the start

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22 Turbocharged engines with after- or inter-cooling can increase fuel efficiency, but it is the air intake cooling that provides the actual NO_x control. Clean fuels with low nitrogen contents do reduce NO_x produced from fuel-bound nitrogen. However, the amount of NO_x produced from the fuel-bound nitrogen in distillate fuel oil constitutes only a small fraction of the total NO_x. Lean burn, air-to-fuel ratio control, and preventative maintenance are more related to engine performance than NO_x control.

23 Khair, Magdi K. DieselNet Technology Guide. *Engine Design for NO_x Control.* May 2002.

24 DieselNet Technology Guide. *Engine Design for Low Emissions.* March 2003.

25 Ibid. footnote 24.

26 Genesis Engineering Inc. & Levelton Engineering Ltd. *Non-Road Diesel Emissions Reduction Study*. October 14, 2003.

27 Ibid. footnote 24.

of combustion. These designs are intrinsic to the particular model of engine associated with each RBLC determination for LND.

Although not listed in the RBLC or CA-BACT, exhaust gas recirculation (EGR) is a new diesel engine NO_x combustion control technology which is becoming commercially available. In October 2002, several heavy-duty engine manufacturers introduced their new EPA-certified engines equipped with EGR systems.[28] EGR is a method by which a portion of the engine's exhaust gas is returned to its combustion chambers via the inlet system in order to reduce thermal NO_x formation. In general, the most important factor contributing to the NO_x reduction effect of EGR is the decrease in the peak combustion temperature caused by the heat adsorption and oxygen reduction effects of the returned inert exhaust gas. The NO_x emission benefit of EGR comes at a cost: increased PM, HC, and CO emissions, a fuel economy penalty, and potential engine wear and durability issues.[29] EGR demonstration tests have shown NO_x reductions from EGR of 40 to 50 percent.[30]

The only post-combustion exhaust treatment control technology listed in the RBLC and CA-BACT for diesel engines is Selective Catalytic Reduction (SCR). SCR systems use ammonia or urea to selectively reduce NO_x to elemental nitrogen and water. SCR injects ammonia or urea into the exhaust upstream of a catalyst bed. The operating temperature for various catalysts are 175°C to 250°C for platinum catalysts, 300°C to 450°C for vanadium catalysts, and 350°C to 600°C for zeolite catalysts.[31] SCR systems are commonly used on stationary sources,[32] as they require a fixed ammonia or urea tank in a containment area, a fixed catalyst bed and injection system, and a fixed NO_x measurement and control system. Several of the *Discoverer* engines are portable so it is relevant to note that there are no SCR determinations in the RBLC or CA-BACT for engines listed as portable units.[33] An SCR system can achieve approximately 90 percent NO_x reduction.[34]

Regardless of the technology applied to achieve BACT, the control option must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source. EPA has promulgated exhaust emission standards for non-road engines under 40 CFR 89.112 in 1998. Most of the *Discoverer* engines are older than 1998. However, the MLC compressors (540 hp) will be new engines. The 1998 non-road engine regulations are structured in three tiers. In each tier, the emission standards are phased in over several years. Tier 1 standards were phased in from

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[28] Khair, Magdi K. DieselNet Technology Guide. *Exhaust Gas Recirculation.* November 2006.

[29] Ibid. footnote 28.

[30] Ibid. footnote 28.

[31] Ibid. footnote 26.

[32] U.S. EPA. Office of Transportation and Air Quality. *Clean Construction USA, Retrofit Strategies.* September 28, 2007.

[33] RBLC ID MS-0086 is incorrectly listed as a portable unit. This engine was a temporary unit that Chevron Products Company rented for 9 months for use at a single location (i.e., stationary unit). It was then removed from the site. Brown, Carla. Mississippi Department of Environmental Quality. [Communication with D. Steen, Air Sciences Inc.]. February 9, 2009.

[34] Ibid. footnote 26.

1996 to 2000. The more stringent Tier 2 standards took effect from 2001 to 2006. The still more stringent Tier 3 standards were phased in between 2006 and 2008. Tier 3 standards apply only for engines from 37-560 kW. The NO_x emission standards for larger generators are provided in Table 4-3.

Table 4-3: EPA Tier 1-3 Nonroad Diesel Engine NO_x Emission Standards

Engine Power	Tier	Year	$NMHC+NO_x$ g/kWh (g/bhp-hr)	NO_x g/kWh (g/bhp-hr)
225 ≤ kW < 450	Tier 1	1996	-	9.2 (6.9)
(300 ≤ hp < 600)	Tier 2	2001	6.4 (4.8)	-
	Tier 3	2006	4.0 (3.0)	-
450 ≤ kW < 560	Tier 1	1996	-	9.2 (6.9)
(600 ≤ hp < 750)	Tier 2	2002	6.4 (4.8)	-
	Tier 3	2006	4.0 (3.0)	-
kW ≥ 560	Tier 1	2000	-	9.2 (6.9)
(hp ≥ 750)	Tier 2	2006	6.4 (4.8)	-

NMHC Non-methane hydrocarbons.

Diesel-Fired Boilers

There are two 8 MMBtu/hr boilers on the *Discoverer*. The available NO_x combustion control technologies for diesel-fired boilers less than or equal to 100 MMBtu/hr identified in the RBLC and CA-BACT, and show in Table 4-2, are LNB, FGR, and good combustion practices. LNB combustion system reduces thermal NO_x by reducing the peak combustion temperature relative to conventional burners. LNB designs are specific to the manufacturer. FGR reduces NO_x emissions by recirculating a portion of the boiler flue gas into the main combustion chamber. This process reduces the peak combustion temperature and lowers the percentage of oxygen in the combustion air/flue gas mixture, thus retarding the formation of thermal NO_x.

Waste Incinerator

The available NO_x combustion control technologies for waste incinerators identified in the RBLC and CA-BACT, and shown in Table 4-2, are SNCR and good combustion practices. The SNCR process involves injecting either ammonia or urea into the firebox of the incinerator, at a location where the flue gas is between 1,600°F and 2,100°F, to react with the NO_x formed in the combustion process. The resulting products of the chemical reaction are elemental nitrogen, carbon dioxide, and water.

4.1.1.1 NO_x BACT for Diesel Generators

Step 2 –Technical Feasibility

As discussed in Section 4.1.2, the available control technologies for the *Discoverer's* six diesel generators (FD-1 through FD-6 – 1,325 hp Caterpillar D399 Marine Generator Set) are ITR, AC, HIP, LND, Tier 2 or 3 level controls, WI, EGR, and SCR. LND, Tier 2 or 3 level controls, EGR, and WI are considered technically infeasible. LND and Tier 2 or 3 level controls are intrinsic to the original engine design which are not part of the Caterpillar D399 design. EGR is not available for these older model engines. WI is considered technically infeasible due to the cold climate in which these generators will operated, the potential engine retrofit incompatibility, the excessive pure water requirements and limited available ship space for storing the water, and the potential engine damage risk associated with this technology.

ITR, AC, and HIP are considered technically feasible for this generator model. SCR is also considered technically feasible because the engines are stationary on the vessel deck.

Step 3 – Control Effectiveness Ranking

The technically feasible control technologies for Generators FD-1 through FD-6 are ranked by control effectiveness as follows:

1. SCR – 90 percent control
2. ITR, AC, and/or HIP – 10 to 50 percent control
3. Good Combustion Practices

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

Shell proposes to apply SCR, the most effective NO_x control option to Generators FD-1 through FD-6. Shell acknowledges that there is ammonia slip associated with SCR.

Step 5 – Selection of BACT

Shell proposes to employ SCR technology to achieve 0.5 gram/kW-hr. DEC Marine, the supplier to several other vessels applying SCR, indicates this is the highest efficiency control available for the *Discoverer's* diesel-fired generators[35].

4.1.1.2 NO_x BACT Smaller Diesel Engines

Step 2 –Technical Feasibility

The *Discoverer's* small diesel engines include:

- FD-12 and FD-13, HPU Engines – 250 hp Detroit 8V-71,
- FD-14 and FD-15, Cranes – 365 hp Caterpillar D343,
- FD-16 and FD-17, Cementing Units – 335 hp Detroit 8V-71N,
- FD-18, Cementing Unit – 147 hp GM 3-71,
- FD-19, Logging Winch – 128 hp Detroit 4-71N, and
- FD-20, Logging Winch – 36 kW 4024TF270.

[35] Ibid. footnote 1.

As discussed in Section 4.1.2, the available control technologies for engines under 500 hp are ITR, AC, LND, WI, and good combustion practices. LND, EGR, and WI are considered technically infeasible. LNDs are intrinsic to the original engine design which are not part of the design for these engines. EGR was not available for these older model engines. WI is considered technically infeasible due to the cold climate in which these generators will operated, the potential engine retrofit incompatibility, the excessive pure water requirements and limited available ship space for storing the water, and the potential engine damage risk associated with this technology.

There are no determinations for installing SCR on diesel engines under 500 hp. This implies that SCR has not previously been deemed BACT for this diesel engine category due to technical infeasibility and/or energy, environmental, and/or economic impacts. In addition, the HPUs, cranes, and logging units are portable in the sense that the units move during use. Portable commercial retrofit SCR tailpipe systems, which include urea tanks, are not available, so this control option is considered technically infeasible as retrofits for these units.

The cementing units are stationary on the vessel deck; Shell is unaware of any instance where SCR technology has been installed on deck-utility engines (under 500 hp) on exploration vessels. While it may be technically feasible in some applications, SCR controls on the *Discoverer* could only be installed in a horizontal configuration. Because the SCR units have a footprint approximately double that of the cementing engines, SCR would consume too much deck space and would seriously affect the safety of necessary nearby deck operations. This impact to safety of operations makes SCR technically infeasible for implementation on the *Discoverer*.

ITR and AC are considered technically feasible for these engines.

Step 3 – Control Effectiveness Ranking

The technically feasible control technologies for Engines FD-12 through FD-20 are ranked by control effectiveness as follows:

1. ITR and AC – 10 to 50 percent control
2. ITR – up to 40 percent control
3. AC – approximately 10 percent control
4. Good Combustion Practices

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

As discussed in Section 4.1.2, ITR and AC reduce NO_x at the expense of incomplete combustion; this increases PM, VOC, and CO emissions, reduced fuel economy, and contaminates the lube oil with soot.[24] Furthermore, as discussed below, Engines FD-12 through FD-20 will be equipped with CDPF controls to reduce PM and CO emissions. CDPF requires a degree of combustion control, so it is likely that ITR will have a negative effect on this control. Due to these energy and environmental considerations, neither ITR nor AC is considered BACT.

Step 5 – Selection of BACT

Shell proposes good combustion practice as BACT for *Discoverer's* diesel-fired small engines. Good combustion practices require operating and maintaining the equipment according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions.

4.1.1.3 NO_x BACT Diesel Compressors

Step 2 –Technical Feasibility

As discussed in Section 4.1.2, the available control technologies for the *Discoverer's* three diesel MLC compressors (FD-9 through FD-11 – 540 hp Caterpillar C-15 engines) are ITR, AC, HIP, LND, Tier 2 or 3 level controls, WI, EGR, and SCR. Tier 2 or 3 level controls are considered technically feasible for this engine model, as it is already configured to meet the Tier 3 emission standards. Since these engines are designed and tuned to meet Tier 3, they are incompatible with incorporating combustion control technologies such as ITR, AC, HIP, LND, and EGR on top of the Tier-3 controls. Note, the C-15 combustion control technology for meeting Tier 3 already incorporates the technologies of cooling and EGR.[36]

WI is considered technically infeasible due to the cold climate in which these generators will operated, the potential engine retrofit incompatibility, the excessive pure water requirements and limited available ship space for storing the water, and the potential engine damage risk associated with this technology.

The MLC compressors (Caterpillar C-15) engines are portable (moved back and forth from storage to operating location when needed due to limited deck space). There are no determinations for installing SCR on portable diesel engines. This implies that SCR is not BACT for the portable engines due to technical infeasibility and/or due to energy, environmental, and/or economic impacts. Shell is not aware of any instance where this control technology has been installed on deck-utility engines of this small size on exploration vessels previously. Additionally, the SCR units could only be installed in a horizontal configuration (they have a footprint approximately double that of the air compressors) which consumes limited and valuable deck space and seriously impacts the safety of necessary nearby deck operations. The portable nature of the engines and this impact to safety of operations makes SCR technically infeasible.

Step 3 – Control Effectiveness Ranking

The technically feasible control technologies for Engines FD-9 through FD-11 are ranked by control effectiveness as follows:

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[36] Caterpillar brochure. *Cat® C15 for Fleet and Line Haul Performance, ACERT™ Technology for 2007*.

1. Tier 3 Emission Standards of 4.0 g/kWh of $NMHC+NO_x$
2. Tier 2 Emission Standards of 6.4 g/kWh of $NMHC+NO_x$
3. Good Combustion Practices.

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

Shell proposes that the Tier 3 emissions standards are the BACT and that additional evaluation is not required. However, it is important to note that the Tier 3 Emission Standards also limit CO and PM emissions.

Step 5 – Selection of BACT

Shell proposes the Tier 3 Emission Standards of 4.0 g/kWh of $NMHC+NO_x$ as BACT for *Discoverer's* diesel-fired compressors.

4.1.1.4 NO_x BACT Boilers

Step 2 –Technical Feasibility

There are two boilers (FD-21 and FD-22 – 8 MMBtu/hr Clayton 200) providing general heat to the *Discoverer*. Only one boiler will operate at a time and the second will serve as a backup. As discussed in Section 4.1.2, the available control technologies for these boilers are LNB, FGR, and good combustion practices. LNB and FGR are considered technically infeasible for this model boiler. The LNB option for this boiler is only available for natural gas and propane fuels.[37] The FGR option available for the Clayton 200 diesel boiler is provided as package during the original installation. Clayton Industries (the manufacturer) does not know of any cases where FGR has been retrofitted on an existing unit purchased without FGR, as in the case of the *Discoverer's* boilers.[38]

There are no determinations for installing SCR on diesel boilers under 100 MMBtu/hr. This implies that SCR is not BACT for this diesel boiler category due to technical infeasibility and/or due to energy, environmental, and/or economic impacts. This control technology has never been required (or installed to Shell's knowledge) on utility boilers of this small size on exploration vessels. More importantly, the boilers are located adjacent to the engine room which is being expanded to accommodate SCR on the generators. There is no deck space for additional SCR units beyond those proposed for the generators. Thus, SCR is considered technically infeasible in for this situation.

Step 3 – Control Effectiveness Ranking

The only technically feasible control option for the two boilers (FD-21 and FD-22) is good combustion practices.

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[37] Clayton Industries brochure. *Advanced Low NO_x Technology*. http://www.claytonindustries.com. August 2007.

[38] Services Department. Clayton Industries. [Communication with D. Steen, Air Sciences Inc.]. February 11, 2009.

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

The top control option from Step 3 is proposed as BACT, thus this step is not required.

Step 5 – Selection of BACT

Shell proposes good combustion practice as BACT for *Discoverer's* diesel-fired boilers. Good combustion practices require operating and maintaining the equipment according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions.

4.1.1.5 NO_x BACT Incinerator

Step 2 –Technical Feasibility

As discussed in Section 4.1.2, the available control technologies for the *Discoverer's* incinerator (FD-22 – 276 lb/hr TeamTec/GS500C) are SNCR and good combustion practices. SNCR is considered technically infeasible for this incinerator. The *Discoverer's* incinerator is very small in comparison to the incinerator listed in the RBLC with SNCR (575 tons per day; 48,000 lb/hr). Based on communication with TeamTec, the manufacturer, they are not aware of any control technologies that have been installed on this model of incinerator for control of any of the pollutants.[39] Shell is not aware of any control technology installations on this or similar-sized incinerators.

Step 3 – Control Effectiveness Ranking

The only technically feasible control technology for the incinerator FD-23 is good combustion practices.

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

The top control option from Step 3 is proposed as BACT, thus this step is not required.

Step 5 – Selection of BACT

Shell proposes good combustion practice as BACT for *Discoverer's* incinerator. Good combustion practices require operating and maintaining the equipment according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions.

4.1.2 SO_2 BACT Analysis

Step 1 – Available Control Technologies

The combustion of fuels containing sulfur produces SO_2 emissions. The available SO_2 control technologies for the *Discoverer's* engines, boilers, and incinerator can be characterized by the

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[39] Bulien, Ole. TeamTec Marine Products. [Communication with K. Lewis, Air Sciences Inc.]. February 11, 2009.

following two categories: combustion of low-sulfur fuels and post-combustion exhaust treatment. Post-combustion exhaust treatment relies on the removal of SO_2 from the exhaust stream through adsorption.

The available SO_2 control technologies for the *Discoverer's* engines, boilers, and incinerator were determined based on searches performed on the RBLC and CA-BACT. The search conditions and a summary of the resulting control technologies are provided in Table 4-4. The complete downloads are provided in Appendix C. For the RBLC, only those determinations made after January 1, 1999, were downloaded.

Table 4-4: Available SO_2 Control Technologies

Source Category	Clearinghouse	Search Conditions	Control Technologies
Diesel IC Engines (>500 hp)	RBLC	Process Code = 17.110	None, LSF
	CA-BACT	I.C. Engines - CI, Non-Emergency (>500 hp)	None, LSF
Diesel IC Engines (≤500 hp)	RBLC	Process Code = 17.210	None, LSF
	CA-BACT	I.C. Engines - CI, Non-Emergency (≤500 hp)	None, LSF
Boiler (≤100 MMBtu/hr)	RBLC	Process Code = 13.220	None, LSF
	CA-BACT	Boilers – Oil Fired (≤100 MMBtu)	No determinations
Incinerator	RBLC	Process Description = Incinerator; Fuel = Solid Waste	None, LSF, SDS
	CA-BACT		No determinations

CI Compression Ignition.

Process Code Key:

17.110 - Large Internal Combustion Engines (>500 HP); Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

17.210 - Small Internal Combustion Engines (≤500 HP); Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

13.220 - Commercial/Institutional-Size Boilers/Furnaces (≤100 million BTU/H); Distillate Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

Control Technology Key:

- LSF Low Sulfur Fuel (defined as ≤0.1 weight percent sulfur for the purpose of this analysis)
- SDS Semi-Dry Scrubber
- None No specific technology listed

The available SO_2 control technology for diesel engines and diesel-fired boilers less than or equal to 100 MMBtu/hr identified in the RBLC and CA-BACT is the use of Low Sulfur Fuel (LSF). For the purpose of this analysis, LSF is considered to be 0.1 percent sulfur by weight or less. Fuel sulfur contents listed in the RBLC and CA-BACT determinations ranged from ≤0.0015 to ≤0.5 weight percent. The most prevalent fuel sulfur contents listed for the diesel engines and diesel-fired boilers were ≤0.05 and ≤0.15 weight percent, respectively.

For the *Discoverer's* incinerator, SO_2 is produced from the combustion of the diesel fuel used to heat the furnace and the combustion of solid waste which typically contains small amounts of sulfur. The RBLC and CA-BACT listed LSF and Semi-Dry Scrubber (SDS) as the available control technologies for waste incinerators. In a SDS, particles of an alkaline sorbent are injected into a flue gas and SO_2 is adsorbed producing a solid by-product.

4.1.2.1 SO_2 BACT for the Diesel Engines and Boilers

Step 2 –Technical Feasibility

As discussed in Section 4.1.3, the available control technology for the *Discoverer's* diesel engines and diesel-fired boilers is LSF. LSF is considered technically feasible for these diesel combustion units.

Shell notes that wet scrubbers were not identified as control options for internal combustion engines and small boilers in the RBLC or the CA-BACT databases. In fact, wet scrubbers may be technically feasible, but were determined by the BACT analyses to not be cost effective because emissions from small units are low. In fact, it is not uncommon at land-based industrial facilities to use wet scrubbers to control SO_2 emissions from large boilers that combust low-sulfur fuels. However, that approach would not be technically feasible in the case of the *Discoverer* for a number of reasons, including the lack of space for the scrubber, the lack of fresh water, and the lack of space for the solid waste material that forms from scrubbing SO_2. In addition, there would be substantial concerns about keeping the scrubber water in a liquid state in the Arctic environment and generators would have to be operated more in order to produce electricity for the scrubber operation. Shell is confident that wet scrubbers would not be technically feasible in this application.

Step 3 – Control Effectiveness Ranking

The technically feasible control technologies for the *Discoverer's* diesel engines and diesel-fired boilers are ranked by control effectiveness as follows.

1. Ultra-low sulfur fuel: ≤0.0015 weight percent sulfur (15 ppm).
2. Low sulfur diesel: ≤0.05 weight percent sulfur.
3. Higher sulfur diesel fuels: >0.05 weight percent sulfur.

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

The top control option from Step 3 is proposed as BACT so additional analyses are not warranted.

Step 5 – Selection of BACT

Shell proposes the exclusive use of ultra-low sulfur diesel, which is the lowest sulfur diesel fuel available, as BACT for *Discoverer's* diesel engines and diesel-fired boilers.

4.1.2.2 SO_2 BACT for the Incinerator

Step 2 –Technical Feasibility

As discussed in Section 4.1.3, the available control technologies for the *Discoverer's* incinerator are LSF and SDS. SDS is considered technically infeasible for this incinerator. The *Discoverer's* incinerator is very small in comparison to the incinerator listed in the RBLC with SDS (350 tons per day; 29,000 lb/hr). Based on communication with TeamTec, the manufacturer, they are not aware of any control technologies that have been installed on this model of incinerator for control of any of the pollutants.[40] Shell is not aware of any control technology installations on this or similar-sized incinerators.

LSF is considered technically feasible.

Step 3 – Control Effectiveness Ranking

The technically feasible control technologies for the *Discoverer's* incinerator are ranked by control effectiveness as follows.

1. Ultra-low sulfur fuel – ≤0.0015 weight percent sulfur.
2. Non-low sulfur fuel.

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

The top control option from Step 3 is proposed as BACT and additional analyses are not warranted.

Step 5 – Selection of BACT

To minimize SO_2 production from the diesel used to heat the furnace, Shell proposes the exclusive use of ultra-low sulfur diesel, which is the lowest sulfur diesel fuel available, as BACT for *Discoverer's* incinerator.

4.1.3 Particulate Matter BACT Analysis

This section addresses BACT for particulate matter, which we refer to generically as PM. We acknowledge that virtually all the PM is PM_{10} and $PM_{2.5}$.

Step 1 – Available Control Technologies

Diesel PM is a complex mixture of compounds which are formed through a number of different mechanisms. PM is comprised of the soluble organic fraction (SOF), the insoluble (solid) fraction, and the sulfate fraction. Fuel and lube oil contribute to the SOF fraction. The insoluble fraction is primarily dry carbonaceous soot from "too-rich-to-burn" fuel combustion. The sulfate fraction is produced from the sulfur in diesel fuel. This fraction can only be controlled by limiting fuel sulfur content.

The available PM control technologies for the *Discoverer's* engines, boilers, and incinerator were determined from searches performed on the RBLC and the CA-BACT. The search conditions and a summary of the resulting control technologies are provided in Table 4-5. The complete downloads are provided in Appendix C. For the RBLC, only those determinations made after January 1, 1999, were downloaded.

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[40] Ibid. footnote 39.

Table 4-5: Available PM Control Technologies

Source Category	Clearinghouse	Search Conditions	Control Technologies
Diesel IC Engines (>500 hp)	RBLC	Process Code = 17.110	None, LSF, PCV, Tier 2/3
	CA-BACT	I.C. Engines - CI, Non-Emergency (>500 hp)	None, OxyCat, LSF, PCV, DPF
Diesel IC Engines (≤500 hp)	RBLC	Process Code = 17.210	None, LSF, PCV
	CA-BACT	I.C. Engines - CI, Non-Emergency (≤500 hp)	None, LSF, PCV
Boiler (≤100 MMBtu/hr)	RBLC	Process Code = 13.220	None
	CA-BACT	Boilers – Oil Fired (≤100 MMBtu)	No determinations
Incinerator	RBLC	Process Description = Incinerator; Fuel = Solid Waste	None, ESP
	CA-BACT		No determinations

CI Compression Ignition.

Process Code Key:

17.110 - Large Internal Combustion Engines (>500 HP); Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

17.210 - Small Internal Combustion Engines (≤500 HP); Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

13.220 - Commercial/Institutional-Size Boilers/Furnaces (≤100 million BTU/H); Distillate Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

Control Technology Key:

DPF	Diesel Particulate Filter
LSF	Low Sulfur Fuel
OxyCat	Oxidation Catalyst
PCV	Positive Crankcase Ventilation
TIER 2/3	EPA Non-Road Engine Emission Standards per 40 CFR 89.112
None	No specific technology listed or good combustion practices

Diesel Engines

The available PM combustion control technologies for diesel engines identified in the RBLC and CA-BACT, and show in Table 4-5, are LSF, oxidation catalyst (OxyCat), diesel particulate filter (DPF), Tier 2 or 3 level controls, and positive crankcase ventilation (PCV). Although not listed in the RBLC or CA-BACT, the combination of OxyCat and DPF referred to as catalytic diesel particulate filter (CDPF) in also an available control technology for PM reduction.

LSF reduces the sulfate PM fraction by limiting the amount of sulfur in the fuel that is available for sulfate formation. An OxyCat removes the SOF of PM through catalytic oxidation of the combustible organic matter resulting in an overall PM control efficiency of 50 percent.[41] A DPF removes the insoluble (solid) fraction of PM (soot) by filtration with an overall PM control

[41] Holmström, Per. D.E.C. Marine AB. [Communication with R. Steen, Air Sciences Inc.]. February 9, 2009.

efficiency of 40 to 50 percent.[42,43] CDPFs remove both the SOF and the insoluble fraction of PM with an overall PM control efficiency of 85 percent.[44]

The crankcase of a combustion engine accumulates gases and oil mist called blowby that leak into the crankcase from the combustion chamber and other sources. The blowby gases must be vented from the crankcase to prevent damage. Due to the fact that blowby gas contains PM, which is 100 percent SOF,[45] it should be handled such that it does not contribute to PM emissions. The PCV system was developed to remove blowby from the engine and to prevent those vapors from being expelled into the atmosphere. The PCV system does this by directing the blowby back to the intake manifold so it can be combusted.

Regardless of the technology applied to achieve BACT, the control option must result in an emission rate no less stringent than the applicable NSPS emission rate, if any NSPS standard for that pollutant is applicable to the source. As discussed above in the NO_x BACT analysis, EPA has promulgated exhaust emission standards for non-road engines under 40 CFR 89.112 in 1998. Engines designed to meet Tier 2 or 3 PM emission standards typically employ a combination of low PM emitting engine designs and DPF or CDPF.[46] The overall PM control for Tier 3 engines is 85 percent.[47] The NSPS PM emission standards for larger generators are provided in Table 4-6.

Table 4-6: EPA Tier 1-3 Non-road Diesel Engine PM Emission Standards

Engine Power	Tier	Year	PM g/kWh (g/bhp-hr)
225 ≤ kW < 450	Tier 1	1996	0.54 (0.4)
(300 ≤ hp < 600)	Tier 2	2001	0.2 (0.15)
	Tier 3	2006	0.2 (0.15)
450 ≤ kW < 560	Tier 1	1996	0.54 (0.4)
(600 ≤ hp < 750)	Tier 2	2002	0.2 (0.15)
	Tier 3	2006	0.2 (0.15)
kW ≥ 560	Tier 1	2000	0.54 (0.4)
(hp ≥ 750)	Tier 2	2006	0.2 (0.15)

Diesel-Fired Boilers

42 Khair, Magdi K. DieselNet Technology Guide. *Engine Design for PM Control.* May 2002.

43 Majewski, Addy W. DieselNet Technology Guide. *Diesel Particulate Filters.* July 2001.

44 California EPA. Air Resource Board. *Verification Procedure - Currently Verified, CleanAIR Systems PERMIT*. January 26, 2009. http://www.arb.ca.gov/diesel/verdev/vt/cvt.htm

45 Jaaskelainen, Hannu. DieselNet Technology Guide. *Crankcase Ventilation.* January 2009.

46 Ibid. footnote 36.

47 The Tier 3 PM emission standard for large non-road engines is 0.2 g/kWh or 0.15 g/hp-hr. The base case is considered to be approximately 1 g/hp-hr.

As shown in Table 4-5, there are no PM control technologies listed in the RBLC and CA-BACT for diesel-fired boilers less than or equal to 100 MMBtu/hr. Therefore, good combustion practices and the combustion of clean diesel fuel is the only available control technology for consideration in this analysis.

Incinerators

The available PM control technologies for incinerators identified in the RBLC and CA-BACT, and show in Table 4-5, are electrostatic precipitators (ESP) and good combustion practices. An ESP uses electrostatic charges to move particulates from a gas stream onto a collection surface. The electric field is created through electrodes that are maintained at a high voltage.

4.1.3.1 PM BACT for the Diesel Engines

Step 2 –Technical Feasibility

As discussed in Section 4.1.4, the available control technologies for the *Discoverer's* diesel engines are LSF, OxyCat, DPF, CDPF, Tier 2 or 3 level controls, and PCV. Tier 2 or 3 level controls and PCV are intrinsic to the original engine design. Therefore, these control technologies are only considered technically feasibility if they are already a part of the design of the *Discoverer's* diesel engines; (e.g., *Discoverer's* three diesel MLC compressors, FD-9 through FD-11 – 540 hp Caterpillar C-15 engines, are configured to meet the Tier 3 emission standards). LSF, OxyCat, DPF, and CDPF are all considered technically feasible for all of the *Discoverer's* diesel engines except the Cat D399s (FD-1 through 6) that also have SCR control. D. E. C. Marine only offers to do a feasibility analysis if CDPFs are to be considered and note that, if a feasible design can be developed, that maintenance of the CDPFs will be required monthly.[48]

Step 3 – Control Effectiveness Ranking

The technically feasible control technologies for the *Discoverer's* diesel engines are ranked by control effectiveness as follows:

1. CDPF – 85 percent control (technically feasible for all engines except Caterpillar D399 with SCR); Tier 3 – 85 percent control (technically feasible for the Caterpillar C-15 engines only),
2. OxyCat – 50 percent control,
3. DPF – 40 to 50 percent control,
4. Good Combustion Practices.

LSF is included in all the above technologies.

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

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[48] Ibid footnote 41.

For the *Discoverer's* six diesel generators (FD-1 through FD-6 – 1,325 hp Caterpillar D399 Marine Generator Set), the top control option (CDPF) is commercially infeasible. Furthermore, as demonstrated in Appendix C, the cost CDPF for these diesel generators is approximately $20,000 to $30,000 per ton of PM removed. This is not cost effective.

For the *Discoverer's* three diesel MLC compressors (FD-9 through FD-11 – 540 hp Caterpillar C-15), the top control option from Step 3 (Tier 3 emission controls) is proposed as BACT; additional analysis of other impacts is not required.

For the *Discoverer's* small diesel engines (FD-12 and FD-13, HPU Engines – 250 hp Detroit 8V-71; FD-14 and FD-15, Cranes – 365 hp Caterpillar D343; FD-16 and FD-17, Cementing Units – 335 hp Detroit 8V-71N; FD-18, Cementing Unit – 147 hp GM 3-71; FD-19, Logging Winch – 128 hp Detroit 4-71N; and FD-20, Logging Winch – 36 kW 4024TF270), the top control option from Step 3 (CDPF) is proposed as BACT, thus this step is not required.

Step 5 – Selection of BACT

Shell proposes the following control options as BACT:

- Diesel generators (FD-1 through FD-6) – OxyCat,
- Diesel MLC compressors (FD-9 through FD-11) – Tier 3,
- Small diesel engines (FD-12 through FD-20) – CDPF.

4.1.3.2 PM BACT for the Diesel-Fired Boilers

Step 2 –Technical Feasibility

There are two boilers (FD-21 and FD-22 – 8 MMBtu/hr Clayton 200) providing general heat to the *Discoverer*. Only one boiler will be operating and the second will serve as a backup. As discussed in Section 4.1.4, the only available PM control technology for these boilers is good combustion practices.

Step 3 – Control Effectiveness Ranking

The only technically feasible control technologies for the two boilers (FD-21 and FD-22) is good combustion practices.

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

The top control option from Step 3 is proposed as BACT, thus this step is not required.

Step 5 – Selection of BACT

Shell proposes good combustion practice as BACT for *Discoverer's* boilers. Good combustion practices require operating and maintaining the equipment according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions.

4.1.3.3 PM BACT for the Incinerator

Step 2 –Technical Feasibility

As discussed in Section 4.1.4, the available control technologies for the *Discoverer's* incinerator (FD-22 – 276 lb/hr TeamTec/GS500C) are ESP and good combustion practices. ESP is considered technically infeasible for this incinerator. The *Discoverer's* incinerator is very small in comparison to the incinerator listed in the RBLC with SNCR (350 tons per day; 29,000 lb/hr). In communication with TeamTec, the manufacturer, they are not aware of any control technologies that have been installed on this model of incinerator for control of any of the pollutants.[49] Shell is not aware of any control technology installations on this or similar-sized incinerators.

Step 3 – Control Effectiveness Ranking

The only technically feasible control technologies for the incinerator FD-23 is good combustion practices.

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

The top control option from Step 3 is proposed as BACT, thus this step is not required.

Step 5 – Selection of BACT

Shell proposes good combustion practice as BACT for *Discoverer's* incinerator. Good combustion practices require operating and maintaining the equipment according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions.

4.1.4 CO BACT Analysis

Step 1 – Available Control Technologies

The available CO control technologies for the *Discoverer's* engines, boilers, and incinerator were determined from searches performed on the RBLC and the CA-BACT. The search conditions and a summary of the resulting control technologies are provided in Table 4-7. The complete downloads are provided in Appendix C. For the RBLC, only those determinations made after January 1, 1999, were downloaded.

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[49] Ibid. footnote 40.

Table 4-7: Available CO Control Technologies

Source Category	Clearinghouse	Search Conditions	Control Technologies
Diesel IC Engines (>500 hp)	RBLC	Process Code = 17.110	None, OxyCat, Tier 2/3
	CA-BACT	I.C. Engines - CI, Non-Emergency (>500 hp)	None, OxyCat
Diesel IC Engines (≤500 hp)	RBLC	Process Code = 17.210	None
	CA-BACT	I.C. Engines - CI, Non-Emergency (≤500 hp)	None, OxyCat
Boiler (≤100 MMBtu/hr)	RBLC	Process Code = 13.220	None
	CA-BACT	Boilers – Oil Fired (≤100 MMBtu)	No determinations
Incinerator	RBLC	Process Description = Incinerator; Fuel = Solid Waste	None
	CA-BACT		No determinations

CI Compression Ignition.

Process Code Key:

17.110 - Large Internal Combustion Engines (>500 HP); Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

17.210 - Small Internal Combustion Engines (≤500 HP); Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

13.220 - Commercial/Institutional-Size Boilers/Furnaces (≤100 million BTU/H); Distillate Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel).

Control Technology Key:

OxyCat Oxidation Catalyst
TIER 2/3 EPA Non-Road Engine Emission Standards per 40 CFR 89.112
None No specific technology listed or good combustion practices

Diesel Engines

The available CO combustion control technologies for diesel engines identified in the RBLC and CA-BACT are OxyCat and Tier 2 or 3 level controls. OxyCat reduces CO emission through catalytic oxidation of these combustible gases, resulting in an overall CO control efficiency of 80 percent.[50] Engines designed to meet Tier 2 or 3 emission standards typically employ a combination of advanced combustion technology and catalytic oxidation. The CO control for Tier 3 engines is assumed to be similar to a CDPF (80 percent[51]). Although not listed in the RBLC or CA-BACT, CDPF reduces CO emission through catalytic oxidation with an overall control efficiency of 80 percent.[52]

Regardless of the technology applied to achieve BACT, the control option must result in an emission rate no less stringent than the applicable NSPS emission rate, if any NSPS standard for that pollutant is applicable to the source. As discussed above in the NO_x and PM BACT analyses,

[50] Ibid. footnote 1.

[51] CleanAIR Systems, Inc. *PERMIT™ Filter CleanAIR Catalyzed Diesel Particulate Filters Installation and Maintenance Manual*. 2006.

[52] Ibid. footnote 51.

EPA promulgated exhaust emission standards for non-road engines under 40 CFR 89.112 in 1998. The CO emission standards for larger generators are provided in Table 4-8.

Table 4-8: EPA Tier 1-3 Nonroad Diesel Engine CO Emission Standards

Engine Power	Tier	Year	CO g/kWh (g/bhp-hr)
225 ≤ kW < 450	Tier 1	1996	11.4 (8.5)
(300 ≤ hp < 600)	Tier 2	2001	3.5 (2.6)
	Tier 3	2006	3.5 (2.6)
450 ≤ kW < 560	Tier 1	1996	11.4 (8.5)
(600 ≤ hp < 750)	Tier 2	2002	3.5 (2.6)
	Tier 3	2006	3.5 (2.6)
kW ≥ 560	Tier 1	2000	11.4 (8.5)
(hp ≥ 750)	Tier 2	2006	3.5 (2.6)

Diesel-Fired Boilers

There are no CO control technologies listed in the RBLC and CA-BACT for diesel-fired boilers less than or equal to 100 MMBtu/hr. Therefore, good combustion practices and the combustion of clean diesel fuel is the only available control technology for consideration in this analysis.

Incinerators

There are no CO or VOC control technologies listed in the RBLC and CA-BACT for waste incinerators. Therefore, good combustion practices and the combustion of clean diesel fuel is the only available control technology for consideration in this analysis.

4.1.4.1 CO BACT for the Diesel Engines

Step 2 –Technical Feasibility

As discussed in Section 4.1.5, the available control technologies for the *Discoverer's* diesel engines are OxyCat, CDPF, and Tier 2 or 3 level controls. Tier 2 or 3 level controls are intrinsic to the original engine design. Therefore, these control technologies are only considered technically feasibility if they are already a part of the design of the *Discoverer's* diesel engines; (e.g., *Discoverer's* three diesel MLC compressors, FD-9 through FD-11 – 540 hp Caterpillar C-15 engines, are configured to meet the Tier 3 emission standards.) OxyCat and CDPF are both considered technically feasible for each of the *Discoverer's* diesel engines.

Step 3 – Control Effectiveness Ranking

The technically feasible control technologies for the *Discoverer's* diesel engines are ranked by control effectiveness as follows:

1. CDPF – 80 percent control (technically feasible for all engines); Tier 3 – 80 percent control (technically feasible for the Caterpillar C-15 engines only),
2. OxyCat – 80/70 percent control for CO/VOC, respectively,
3. Good Combustion Practices.

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

For the *Discoverer's* six diesel generators (FD-1 through FD-6 – 1,325 hp Caterpillar D399 Marine Generator Set), the top control option (CDPF) is technically infeasible. Even if it were feasible, it provides the same level of CO control as the next control option (OxyCat). Considering the total capital cost of CDPF of $640,000 for six units, as shown in Appendix C, the economic impact of CDPF does not justify the marginal environmental benefit. CDPF is considered not to be cost-effective.

For the *Discoverer's* three diesel MLC compressors (FD-9 through FD-11 – 540 hp Caterpillar C-15), the top control option from Step 3 (Tier 3 emission controls) is proposed as BACT. Further analysis is not required.

For the *Discoverer's* small diesel engines (FD-12 and FD-13, HPU Engines – 250 hp Detroit 8V-71; FD-14 and FD-15, Cranes – 365 hp Caterpillar D343; FD-16 and FD-17, Cementing Units – 335 hp Detroit 8V-71N; FD-18, Cementing Unit – 147 hp GM 3-71; FD-19, Logging Winch – 128 hp Detroit 4-71N; and FD-20, Logging Winch – 36 kW 4024TF270), the top control option from Step 3 (CDPF) is proposed as BACT. Further analysis is not required.

Step 5 – Selection of BACT

Shell proposes the following control options as BACT:

- Diesel generators (FD-1 through FD-6) – OxyCat
- Diesel MLC compressors (FD-9 through FD-11) – Tier 3
- Small diesel engines (FD-12 through FD-20) – CDPF

4.1.4.2 CO BACT for the Diesel-Fired Boilers

Step 2 –Technical Feasibility

There are two boilers (FD-21 and FD-22 – 8 MMBtu/hr Clayton 200) providing general heat to the *Discoverer*. Only one boiler will be operating and the second will serve as a backup. As discussed in Section 4.1.5, the only available CO control technology for these boilers is good combustion practices.

Step 3 – Control Effectiveness Ranking

The only technically feasible control technologies for the two boilers (FD-21 and FD-22) is good combustion practices.

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

The top control option from Step 3 is proposed as BACT. Further analysis is not required.

Step 5 – Selection of BACT

Shell proposes good combustion practice as BACT for *Discoverer's* boilers. Good combustion practices require operating and maintaining the equipment according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions.

4.1.4.3 CO BACT for the Incinerator

Step 2 –Technical Feasibility

As discussed in Section 4.1.5, the only available control technology for the *Discoverer's* incinerator is good combustion practices.

Step 3 – Control Effectiveness Ranking

The only technically feasible control technologies for the incinerator FD-23 is good combustion practices.

Step 4 – Evaluate the most effective control based on energy, environmental, and economic impacts

The top control option from Step 3 is proposed as BACT. Further analysis is not required.

Step 5 – Selection of BACT

Shell proposes good combustion practice as BACT for *Discoverer's* incinerator. Good combustion practices require operating and maintaining the equipment according to the manufacturer's recommendations to maximize fuel efficiency and minimize emissions.

4.1.5 CO_2 BACT Analysis

Shell recognizes that the EPA is considering whether and how to regulate CO_2 under the Clean Air Act and that the agency may establish by rule or policy a requirement that major sources perform a BACT analysis for CO_2 emissions. At this time, Shell believes it is premature to address projected CO_2 emissions in this permit application for purposes of possible control.

4.2 NSPS

Candidate source types for NSPS applicability (40 CFR 60) are the fuel tanks (Subparts Ka and Kb), the incinerator (Subpart CCCC), the boilers (Subpart Dc), and the internal combustion engines (Subpart IIII).

NSPS Subpart Ka applies to petroleum liquids tanks with a capacity of greater than 420,000 gallons, which is well above tank 21P (142,140 gallons), the largest *Discoverer* tank. NSPS Subpart Kb applies to petroleum liquids tanks manufactured after July 1984. All *Discoverer* tanks were manufactured before 1984, and therefore none are affected sources.

The incinerator has been manufactured in 2006 or later, so NSPS Subpart CCCC is applicable. Since the incinerator will be classified as a CISWI incinerator and qualifies as a small (less than 35 tons per day) Municipal Solid Waste (MSW) incinerator, it will be exempt from most of the CCCC requirements. An exemption request is attached as Appendix G. Its applicable NSPS requirements will consist of the attached initial notification to the EPA administrator and quarterly record-keeping of the waste material burned.

NSPS Subpart Dc is applicable to boilers equal to or greater than 10 MMBtu/hr design capacity. Since the two *Discoverer* boilers are under 10 MMBtu/hr, they are exempt.

All diesel engines, except the cementing engines, were manufactured prior to July 11, 2005, and therefore are exempt from NSPS IIII. The cementing engines, FD-16, 17, and 18, are new Tier 3 engines to which NSPS IIII applies. At a size of less than 10 liters per cylinder, the operator is to operate the engine to meet the manufacturer's Tier 3 emission limits, which translates to applying good maintenance practices (GMP). Shell will practice GMP.

4.3 NESHAPs

The *Discoverer*'s total hazardous air pollutants (HAPs) emissions, including the fleets (Appendix A, Page 9), are estimated at 2.2 tons per year, which are under the 10 tons per year single HAP, and 25 tons per year combined HAPs emission major source threshold, and therefore, the *Discoverer* is categorized as an area source of HAPs per § 63.2 (40 CFR 63, Subpart A - National Emission Standards for Hazardous Air Pollutants – General Provisions – Definitions).

4.3.1 Compression Ignition (CI) Reciprocating Internal Combustion Engines (RICE)

Emission units FD-1 through FD-20 are CI RICE located at an area source of HAPs and thus subject to 40 CFR 63, Subpart ZZZZ (National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines) per § 63.6585. All of these CI RICE, except for FD-16 through FD-18, are constructed before June 12, 2006, and therefore categorized as an existing RICE at area source of HAPs per § 63.6590 (a) (1) (iii). FD-16 through FD-18 commenced (or will commence) construction after June 12, 2006 and therefore qualify as a new RICE at area source of HAPs per § 63.6590 (a) (2) (iii). The existing sources (FD-1 through FD-15, and FD-19 through FD-20) do not have to meet the requirements of 40 CFR 63, Subparts ZZZZ and A, and do not require initial notification per § 63.6590 (b) (3). The new sources (FD-16 through FD-18) are not subject to compliance requirements for this Subpart per § 63.6590 (c).

4.3.2 Commercial and Industrial Solid Waste Incinerator (CISWI)

HAPs emission standards for non-hazardous waste combustors are addressed in applicable NSPS under Section 129 (h) (2) of the 1990 Clean Air Act Amendments. Emission unit FD-23 is a CISWI subject to NSPS under 40 CFR 60, Subpart CCCC, but exempt from requirements of this Subpart, except for notification and recordkeeping, per § 60.2020 (c) (2). Therefore, the HAPs emission standards listed in this Subpart are not applicable to FD-23.

4.3.3 Boilers

Emission units FD-21 and FD-22 are utility boilers on the *Discoverer*. These boilers are not subject to the 40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; because this Subpart is applicable to boilers located at a major source of HAPs per § 63.7485. Therefore, emission units FD-21 and FD-22 are not subject to NESHAPs.

SECTION 5

AMBIENT IMPACTS

Under the New Source Review regulations, 40 CFR Part 52.21, Section k and o, Shell is to demonstrate that source impacts will be in compliance with ambient standards and impairment limits using EPA-acceptable estimation procedures. These procedures involve dispersion modeling as described in Appendix W of Part 51. This application section addresses the methods for modeling the impacts from the *Discoverer* and its associated fleets for demonstration of compliance with the NAAQS (Subpart d) and PSD (Subpart c) increments, listed in Table 5-1. The modeling is performed according to Appendix W of Part 51 (Guideline on Air Quality Models). At EPA Region 10's direction, Shell is applying a conservative screening dispersion modeling for this impact analysis, at least until actual meteorological data can be obtained. The EPA-approved ISC-PRIME model is used herein with EPA screening meteorology and EPA-recommended worst persistence factors for converting one-hour maximum concentrations to other averaging periods.

Compliance is demonstrated at and beyond a 900-meter radius which is within the 1,000-meter safety exclusion zone and the nearest location of public access. Owner-requested restrictions limiting operation of the sources are taken into account in the analysis. This impact analysis demonstrates how the *Discoverer* and associated fleets are modeled in accordance with these regulations as provided in Shell's Frontier Discoverer Alaska Outer Continental Shelf (OCS) Exploratory Drilling Program Air Quality Impact Modeling Protocol (dated November 12, 2008) provided to EPA Region 10.

Table 5-1: Summary of Applicable Standards

Pollutant	Averaging Time	NAAQS [1] ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)
Nitrogen Dioxide (NO_2)	Annual	100	25
Particulate Matter ($PM_{2.5}$)	24-hour	35	NA
	Annual	15	NA
Particulate Matter (PM_{10})	24-hour	150	30
	Annual	50	17
Sulfur Dioxide (SO_2)	3-hour	1,300	512
	24-hour	365	91
	Annual	80	20
Carbon Monoxide (CO)	1-hour	40,000	NA
	8-hour	10,000	NA

[1] National Ambient Air Quality Standards

NA not applicable

5.1 Model Selection

At this time, representative meteorological data meeting the EPA Region 10's dispersion modeling requirements is not available for the Chukchi Sea OCS locations. Thus, the ability to use refined modeling was eliminated, at least for now, and only screening modeling is available to Shell. The most recent version (04269) of the ISC-PRIME dispersion model was used. The ISC-PRIME model is a U.S. EPA-approved, steady-state, multiple-source, Gaussian plume model. It offers a screening mode; it can characterize sources which are substantially affected by building wake effects, such as the source units on the *Discoverer*; it resolves impacts in a three-dimensional receptor grid; and it allows for consideration of the actual spatial distribution of sources, all of which is important in this analysis. The sources in this analysis are distributed over a wide area and the model is capable of characterizing this spatial distribution.

5.2 Worst-Case Meteorological Data

The dispersion model is used with screening meteorology (meteorological assumptions that result in impacts equal to or higher than those to be expected). An ISC-PRIME compatible meteorological data set was generated using the SCREEN3 model's array of possible wind speed and stability combinations. The screening meteorological data contain all possible wind speeds for all of the dispersion categories listed in the U.S. EPA's SCREEN3 Model User's Guide (EPA-454/B-95-004) and as shown in Table 5-2. This meteorological data is considered to contain the theoretical worst-case dispersion conditions regardless of whether these conditions will actually occur at the project locations. The *Discoverer* will have its bow pointing into the wind when it is drilling as described in Section 5.7. Thus, the combinations of speed and stability are applied from a single wind direction (winds blowing from the east to the west).

Table 5-2: Wind Speed and Stability Class Combinations Used for Screening Modeling

Stability	Wind Speed (m/sec)												
	1	1.5	2	2.5	3	3.5	4	4.5	5	8	10	15	20
A	*	*	*	*	*								
B	*	*	*	*	*	*	*	*	*				
C	*	*	*	*	*	*	*	*	*	*	*		
D	*	*	*	*	*	*	*	*	*	*	*	*	*
E	*	*	*	*	*	*	*	*	*				
F	*	*	*	*	*	*	*						

The guidance provided in the SCREEN3 Model User's Guide for mixing heights is utilized as follows. The mixing heights used for neutral and unstable conditions (Classes A-D) are based on an estimate of the mechanically-driven mixing height. The mechanical mixing height for these conditions equals 320 times the wind speed. For stable conditions (Classes E-F), the mixing height is set equal to 10,000 meters to represent unlimited mixing.

Section 3.4 of EPA's Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised (EPA-454/R-92-019, October 1992) document allows the use of measured ambient temperatures in lieu of a default temperature value of 293 K. Per EPA Region 10's recommendation, the ambient temperature for the screening meteorological data is based on the long-term average temperature at Barrow, Alaska. Based on data from the Western Regional Climate Center,[53] from 1949 to 2007, the average daily high and low temperatures at Barrow were 15.7°F and 4.9°F, respectively. Thus, the average of these two values, 10.3°F (261.1°K), was utilized in the screening meteorological data set.

5.3 Persistence Factors

The model in screening mode produces 1-hour maximum impacts. These screening 1-hour concentrations generated by the model are converted to longer-term concentrations by using multipliers (i.e., worst-case persistence factors) required by EPA Region 10. To obtain the estimated maximum concentration for 3-hour, 8-hour, 24-hour, and annual averaging times, the 1-hour average model output is multiplied by the worst-case persistence factor values provided in Table 5-3.

Table 5-3: Worst-Case Persistence Factors

Averaging Period	Persistence Factor [1]
3-hour	1.0
8-hour	0.9
24-hour	0.6
Annual	0.1

[1] Worst-case factors from EPA's Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised (EPA-454/R-92-019, October 1992) document.

5.4 Physical Characterization of the Emission Units

5.4.1 Discoverer

A listing of the physical source release characteristics of the source units and a plan view of the *Discoverer* source unit configuration are provided on Pages 3 and 8 of Appendix B. Stack parameters listed for *Discoverer* sources are representative of 100% load.

Per EPA's Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised (EPA-454/R-92-019, October 1992) document: Sources that emit the same pollutant from

[53] Western Region Climate Center. *Climatological data for Barrow, Alaska*. http://www.wrcc.dri.edu/cgi-bin/cliMAIN.pl?ak0546

several stacks with similar parameters that are within about 100 meters of each other may be analyzed by treating all of the emissions as coming from a single representative stack. Several sources on the *Discoverer* are located next to each other and merging the stacks for modeling purposes is appropriate because of similarities in source size and location. For these, single-source stack parameters with combined emissions are used. Given the configuration of the stacks and structures on the *Discoverer*, plumes may be down-washed and pulled into the buildings' wake region. For this analysis, the building downwash parameters used in ISC-PRIME are calculated using the Building Profile Input Program (BPIP) version (Version 04274). The building height and location information used in the BPIP analysis are provided on Page 9 of Appendix B.

5.4.2 Supporting Fleets

With respect to the modeling of impacts from the fleets associated with the *Discoverer*, the ice management and anchor handling fleet is considered to be a generic fleet and the resupply ship a generic supply ship. There is to be a specifically defined OSR fleet. Emissions from all three are estimated and impacts included in the analyses.

Primary and secondary ice management ship emissions are modeled as line sources at the closest distance to the *Discoverer* at which the ships will normally operate. As described in Section 2.11, when there is ice to be broken the primary ice management ship is normally positioned from 3 miles to 12 miles upwind on the drift line. The width of the swath will be about 3 miles to either side of the drift line and defined by a roughly elliptical movement pattern. The secondary ice management ship will be located from the anchor buoy pattern to 6 miles up-drift from the *Discoverer*, moving laterally 1.5 miles to either side of the drift line and also in an elliptical pattern.

For modeling purposes, the icebreaker emissions are placed on a line nearest the *Discoverer* at 3 miles (4.8 kilometers) upwind and spanning 3 miles (4.8 kilometers) on each side of the drift line. The nearest edge of activity for the anchor handler/ice management ship is 1 kilometer upwind of the *Discoverer* and spanning a line 1.5 miles (2.4 kilometers) on either side of the drift line.

This OSR fleet is expected to consist of one managing oil response ship, the Nanuq, and three small (34-foot) craft that dock on the Nanuq. Typically, the OSR fleet will be operating several miles from the *Discoverer.* The only planned activity for the OSR fleet is training, an 8-hour per day exercise, modeled at the closest normal distance of two kilometers downwind. The training is expected to be contained within a 2-mile area, modeled as a two kilometers line source.

The ice management and OSR fleets are modeled as a series of elevated line sources as described in more detail in the next section.

5.4.3 Volume Source Characterization of Supporting Fleets

In a January 26, 2009, memo from Shell representatives to EPA Region 10,[54] a detailed description of the volume source characterization of the support fleets was provided and based on subsequent discussions with EPA, the following characterization of the support fleets is utilized in the modeling analysis.

The ice management and OSR fleets are characterized in the air quality impact analysis using an elevated line source (series of adjacent volume sources) at the nearest edge of anticipated activity to the *Discoverer*. This configuration is worst-case since, in reality, the ice management fleet will be breaking up ice at and beyond (e.g., further away from the *Discoverer*) the nearest edge of anticipate ice management activity. The line source characterization is designed to simulate the effect of mobile sources moving around and emitting plumes which rise and form a layer of emissions above ground (e.g., smearing in space of a plume from a moving ship) which is then advected downwind towards the *Discoverer*. This design simulates the effect of ice management fleet under its highest emitting scenario, which is a continual churning up of one-year ice drifting toward the *Discoverer*.

Determination of Effective Emission Heights for Volume Sources

According to Section 1.2 in the User's Guide for the Industrial Source Complex (ISC3) Dispersion Models, Volume II - Description of Model Algorithms (EPA-454/95-003b, September 1995), the effective emissions height for elevated volume sources needs to be assigned. The plume heights for the fleet emissions are estimated using SCREEN3 (an alternate screening model that provides a printout of plume rise) which accounts for the mechanical and buoyant lift from the ship's stacks. Per EPA's request, as provided in Section 2.11, Shell has compiled a list of potential ships which could be used for ice management and anchor handling activities. The stack characteristics of the main propulsion engines for each ship are used with the SCREEN3 algorithms to define the plume height for the ice management fleet emissions (in ISC-PRIME) as shown on Appendix B, Page 3. Building downwash information related to these sources in provided on Appendix B, Page 9.

Note that some of the ice management ships have horizontal stacks which are modeled in accordance with Alaska DEC's recommendations. Alaska DEC's recommended adjustments provide for the retention of buoyancy while addressing the impediment to the vertical momentum of the release.

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[54] Martin, Tim, Air Sciences Inc. [Technical memo Herman Wong, EPA Region 10]. Description of Volume Source Characterization of Icebreaker Fleets, Shell *Discoverer* Chukchi Sea Permit Application. January 26, 2009.

The following procedure was utilized to model horizontally emitting stacks:

- Set the actual stack velocity (V_{actual}), in meters per second, to an adjusted stack exit velocity ($V_{adjusted}$) of 0.001 meter per second.
- To conserve volumetric flow, determine an adjusted stack diameter ($D_{adjusted}$) by adjusting the actual stack inside diameter (D_{actual}), in meters, to account for buoyancy of the plume by using the following equation:
- $D_{adjusted} = 31.6(D_{actual})(V_{actual})^{0.5}$

Use the adjusted parameters, $V_{adjusted}$ and $D_{adjusted}$, in the modeling analysis.

These source characteristics and building dimension information were used as inputs to SCREEN3 to obtain an estimate of final plume rise. For every meteorological condition listed in Table 5-2 (including the combination of 20 meters per second, and D stability), SCREEN3 calculates plume rise values and provides a listing of meteorological conditions associated with the maximum-predicted ground-level concentrations at downwind distances from a source. Appendix E provides the SCREEN3 output for each of the ice management ships.

The ice management fleet will be managing ice upwind of the *Discoverer* given the mobile nature of the fleets, the plumes from the fleets will rise and spread out at some height. The final plume rise for each ship was chosen to represent the height of the volume sources for ISC-PRIME. The final plume height for the generic ice management and anchor handler fleet was conservatively chosen as the lowest plume rise value for any ship at 1,000 meters upwind of the *Discoverer*, which the closest location of any ship to *the Discoverer* (see Table 5-4).

In reality, the support ships will typically be located much further away than 1,000 meters from the *Discoverer* and much higher plume rise values would be appropriate. Based on the data highlighted in Table 5-4, the lowest final plume rise for the primary and secondary ice management ships is 35.66 meters (based on worst-case plume rise from the Vladimir Ignatjuk) and is used to define the volume source release heights for the ice management fleet in ISC-PRIME.

Table 5-4: Summary of SCREEN3 Output for Plume Rise

	Minimum Plume Rise from SCREEN3								
Downwind Distance(m)	OSR Fleet	Kapitan Dranitsyn	Fennica/ Nordica	Vladimir Ignatjuk	Talagy	Tor Viking II	Odin Viking II	Balder Viking	Vidar Viking
100	5.41	35.92	33.00	27.25	26.09	32.47	31.76	32.47	32.47
200	7.75	37.18	35.71	33.30	28.48	35.01	44.02	35.01	35.01
300	11.09	39.58	39.50	28.04	31.09	48.03	44.02	48.03	48.03
400	18.06	42.57	43.85	30.34	34.06	48.03	44.02	48.03	48.03
500	18.06	45.32	44.68	30.8	36.53	48.03	44.02	48.03	48.03
600	18.06	47.26	44.68	35.66	36.53	48.03	44.02	48.03	48.03
700	27.33	47.26	44.68	35.66	36.53	48.03	44.02	48.03	48.03
800	27.33	47.26	44.68	35.66	36.53	48.03	44.02	48.03	48.03
900	27.33	47.26	44.68	35.66	36.53	48.03	44.02	48.03	48.03
1,000	28.31	47.26	44.68	35.66	36.53	48.03	44.02	48.03	48.03
1,100	28.31	47.26	44.68	35.66	43.48	48.03	44.02	48.03	48.03
1,200	28.31	47.26	44.68	43.93	43.48	48.03	44.02	48.03	48.03
1,300	28.31	47.26	44.68	43.93	43.48	48.03	44.02	48.03	48.03
1,400	28.31	47.26	44.68	43.93	43.48	48.03	44.02	48.03	48.03
1,500	28.31	50.01	46.53	43.93	43.48	48.03	44.02	48.03	48.03
1,600	28.31	50.01	46.53	43.93	43.48	48.03	44.02	48.03	48.03
1,700	28.31	50.01	46.53	43.93	43.48	48.03	44.02	48.03	48.03
1,800	28.31	50.01	46.53	43.93	43.48	48.03	44.02	48.03	48.03
1,900	28.31	50.01	46.53	43.93	43.48	48.03	44.02	48.03	48.03
2,000	28.31	50.01	46.53	43.93	50.39	48.03	44.02	48.03	48.03
2,100	28.31	50.01	46.53	46.24	50.39	48.03	44.02	48.03	48.03
2,200	28.31	50.01	48.96	43.93	50.39	48.03	44.02	48.03	48.03
2,300	28.31	50.01	48.96	43.93	50.39	48.03	44.02	48.03	48.03
2,400	28.31	50.01	48.96	43.93	50.39	48.03	44.02	48.03	48.03
2,500	28.31	50.01	48.96	43.93	50.39	48.03	44.02	48.03	48.03
2,600	28.31	50.01	48.96	43.93	50.39	48.03	44.02	48.03	48.03
2,700	28.31	50.01	48.96	43.93	50.39	48.03	44.02	48.03	48.03
2,800	28.31	50.01	48.96	43.93	50.39	48.03	44.02	48.03	48.03
2,900	28.31	54.13	48.96	43.93	50.39	48.03	44.02	48.03	48.03
3,000	28.31	54.13	48.96	46.24	50.39	48.03	44.02	48.03	48.03
3,500	28.31	54.13	52.29	46.24	50.39	48.03	44.02	48.03	48.03
4,000	28.31	54.13	52.29	49.16	50.39	48.03	44.02	48.03	48.03
4,500	28.31	54.13	57.09	53.02	50.39	48.03	44.02	48.03	48.03
5,000	28.31	60.79	57.09	53.02	53.15	48.03	44.02	48.03	48.03
5,500	28.31	60.79	57.09	53.02	56.64	48.03	44.02	48.03	48.03
6,000	28.31	60.79	57.09	58.34	56.64	48.03	44.02	48.03	48.03
6,500	28.31	60.79	57.09	58.34	112.28	48.03	44.02	48.03	48.03
7,000	28.31	60.79	64.5	58.34	112.28	48.03	44.02	48.03	48.03
7,500	28.31	60.79	64.5	58.34	112.28	48.03	44.02	48.03	48.03
8,000	28.31	60.79	64.5	66.22	112.28	48.03	44.02	48.03	48.03
8,500	28.31	60.79	64.5	66.22	112.28	48.03	44.02	48.03	48.03
9,000	28.31	72.67	64.5	66.22	112.28	48.03	44.02	48.03	48.03
9,500	28.31	72.67	64.5	66.22	112.28	48.03	44.02	48.03	48.03
10,000	28.31	72.67	64.5	66.22	112.28	48.03	44.02	48.03	48.03

Determination of the Volume Sources Spacing and Dimensions

For each ship, the elevated line source is divided into a series of volume sources and each volume source is assigned initial X, Y, and Z dimensions following Section 1.2 in the User's Guide for the Industrial Source Complex (ISC3) Dispersion Models, Volume II - Description of Model Algorithms (EPA-454/95-003b dated September 1995).

The line source for the primary and secondary ice management ships is composed of a series of adjacent squares with 100 meters on each side. EPA has suggested that the volume sources could be spaced based on the size of the ice management ships which are generally around 100 meters long. The line source for the OSR fleet is composed of a series of adjacent squares, each 50 meters on side. The OSR fleet vessels could potentially range in size from 34-foot (~10 meter) boats, to the Nanuq which is roughly 100 meters in length. The line source of the OSR fleet is composed of a series of adjacent squares which represent both the larger and the smaller ships so a fleet average of approximately 50 meters is used to represent the OSR fleet.

Shell has chosen to conservatively model all emissions from the OSR fleet out of the low stacks of the smaller, 34-foot craft. In reality, the impacts from the OSR fleet are based on emissions from both the smaller craft and the larger Nanuq. For comparison, the stacks of the 34-foot craft are 11 feet above the water while the stack of the Nanuq is approximately 50 feet above the water.

Initial dispersion for volume sources is characterized by two parameters, σy (sigma Y) and σz (sigma Z). For the ice management and anchor handling fleet, the sigma Y value for each volume source is determined by dividing the physical horizontal dimension of the volume, 100 meters, by 2.15 as recommended in the ISC User's Guide. The sigma Y value for each volume of the OSR fleet is 50 meters, divided by 2.15. Thus, the sigma Y values for the OSR fleet and ice management fleet used as input to the ISC-PRIME model are 46.5 and 23.3 meters, respectively. EPA has recommended that Shell utilize the smallest, most conservative sigma Z values predicted by SCREEN3 for input to the ISC-PRIME model. Table 5-5 lists the smallest SCREEN3-predicted sigma Z values for both the OSR and ice management fleets. Based on this table, the sigma Y and sigma Z values for the OSR fleet and ice management fleet are 5.23 meters and 11.02 meters, respectively.

Table 5-5: Minimum Sigma Z Values from SCREEN3

Source Name	SCREEN3 Model ID	Minimum Sigma Z
OSR Fleet	OILSPL3	5.23
Kapitan Dranitsyn	KAPITAN2	17.18
Fennica/Nordica	FENNICA2	15.04
Vladimir Ignatjuk	VLADIGN2	11.02
Talagy	TALAGY	12.1
Tor Viking II	TOR_H	16.68
Odin Viking II	ODIN_H	16.84
Balder Viking	BALD_H	16.68
Vidar Viking	VIDAR_H	16.68

A listing of the assumed locations and source characteristics for the primary and secondary ice management ships and the OSR fleet are provided on Pages 5, 6 and 7 of Appendix B.

5.5 Ambient Air Boundary and Receptors

Shell has submitted a request to the US Coast Guard, for issuance of a safety exclusion and equipment protection zone surrounding the *Discoverer* to a radius of 1,000 meters, which is approximately equal to its anchor pattern radius. To be conservative, an ambient air boundary of 900 meters is used herein. The *Discoverer* is anchored with eight lines equally spaced around the vessel and fanning out from the mooring turret.

To capture maximum screening impacts from the *Discoverer* and its associated fleet, receptors are placed every 100 meters throughout a 13-kilometer by 10-kilometer area covering all activity areas upwind and downwind of the *Discoverer*. Receptors are spaced around the 900-meter boundary every 25 meters. In addition, a high resolution line of receptors is placed downwind of the *Discoverer* spanning the width of the *Discoverer* (three receptors spaced every 15 meters spanning north-south). Receptors on this line (located directly downwind of the *Discoverer)* are spaced: every 25 meters between the exclusion zone and 8 kilometers from the *Discoverer*, every 100 meters from 8 kilometers to 50 kilometers, and every 500 meters beyond 50 kilometers. All maximum impact locations are captured by this high resolution line. Receptor locations for the worst-case modeling scenario are shown on Figure 5-1.

5.6 Positioning of Source Components Including Fleets for Modeling

The screening modeling emissions scenario is developed with the ice management fleet operating upwind of the *Discoverer* to break up any ice so it will flow around it, and the OSR fleet operating downwind of the *Discoverer*, the safe and protected side, and the direction in which any oil spill would drift.

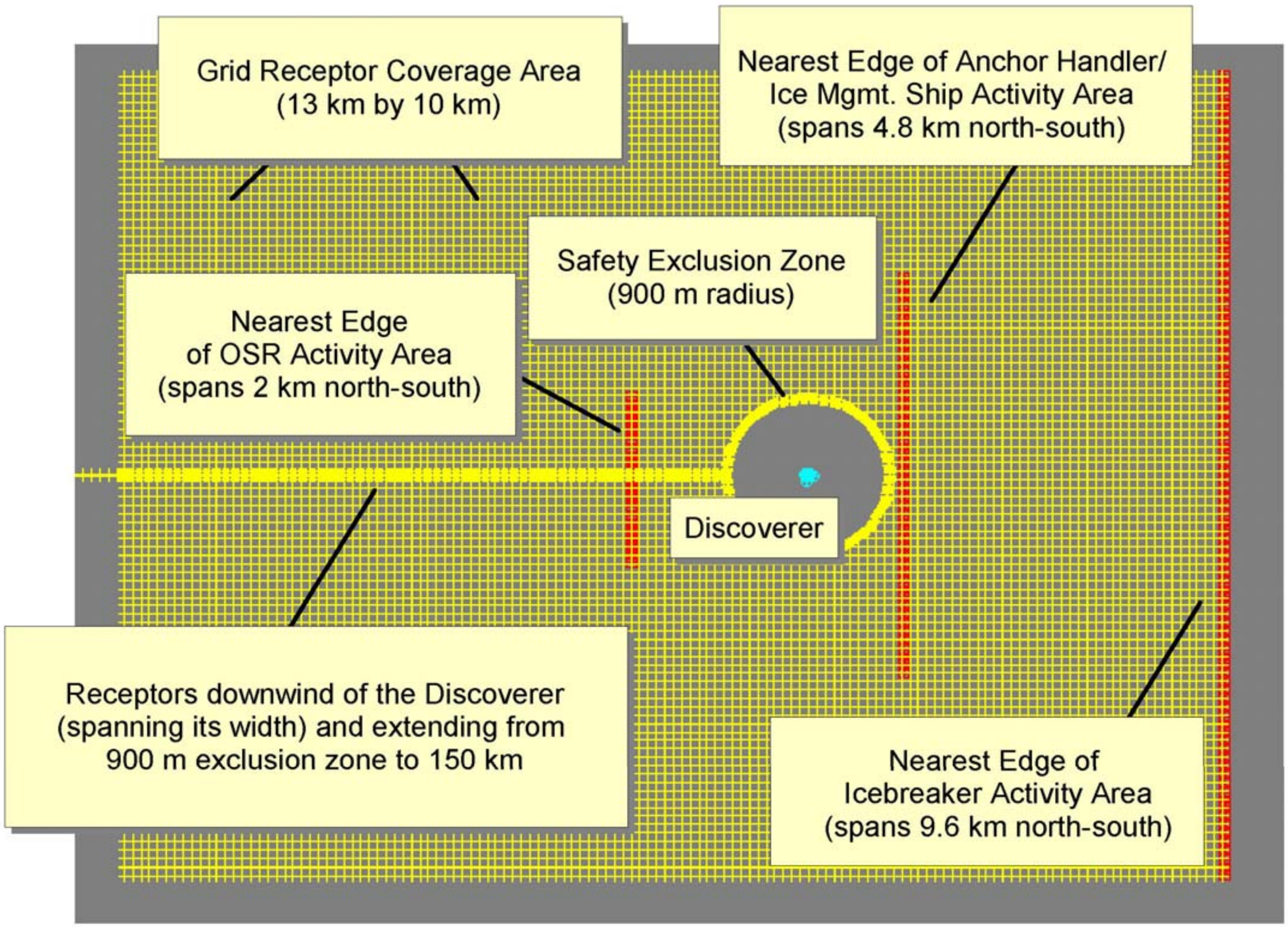
The *Discoverer* will have its bow pointing into the wind when it is drilling. This is accomplished through a mechanical drive that rotates the ring that forms the anchor tie relative to the hull and is for the purpose if minimizing ice buildup on the *Discoverer's* hull during drilling. The selection of the direction from the *Discoverer* in which to locate the fleet is made first by arbitrarily orienting the *Discoverer* with the helideck facing west and the bow facing east as shown on Page 8 of Appendix B. For the impact analysis, the wind is blowing from the east towards the bow of the *Discoverer*.

The fleet spatial orientation includes the OSR fleet operating with the nearest edge of activity located approximately two kilometers downwind of the edge of the *Discoverer*. The two ice management ships (primary and secondary) will be operating upwind of the *Discoverer*. The nearest edge of secondary ice management activity will be 1 kilometer upwind of *Discoverer* and the nearest edge of primary ice management activity will be 4.8 kilometers (3 miles) upwind. The resupply ship emissions are explicitly modeled when the ship is docked to the *Discoverer*. The resupply ship generally ties to the drillship stern first (back of ship) with a 50-foot standoff from the edge of the drillship when onloading/offloading. For this modeling analysis, it is assumed that the resupply ship is continuously located 12 hours per day near the *Discoverer* for 32 days per drilling season. In reality, the resupply ship will only visit the *Discoverer* for a few days per season for 12 hours per visit. These emissions are allowed to be down-washed in the wake of the *Discoverer*, just as the *Discoverer* source units emissions will be to some degree.

Figure 5-1 provides the locations of the *Discoverer* and support fleets for the worst-case impact scenario.

A listing of the assumed locations and source characteristics for the ice management fleet are provided on Pages 6, 7 and 8 of Appendix B.

Figure 5-1: Source and Receptor Locations for Worst-Case Impact Scenario



5.7 PSD Modeling Assessment Phases – Preliminary Analysis and Full Impact Analysis

The PSD requirements provide for land use area classification as a function of the amount of growth of air emission sources and impacts allowed before significant air quality deterioration would occur. Class I areas have the smallest impact increments and thus allow only a small degree of air quality deterioration. Class II areas should be able to accommodate normal, well-managed industrial growth and are afforded a less stringent level of air quality deterioration than Class I areas.

The nearest Class I area (Denali National Park) is located more than 950 km from the proposed Shell activities on the Chukchi Sea OCS. Therefore, impacts to the Class I area are insignificant and are not evaluated in the impact analyses and the following discussion pertains only to impacts at Class II areas.

The PSD modeling analysis involves two phases: a preliminary analysis (referred to as a significant impact analysis) and, if required, a full impact analysis. The preliminary analysis estimates ambient concentrations resulting from the proposed project for pollutants that trigger PSD requirements.

The results of the preliminary analysis determine whether a full impact analysis (facility plus competing regional sources) for a particular pollutant is necessary. If the ambient impacts from the preliminary analysis are greater than the PSD Significant Impact Levels (SILs) shown in Table 5-6 then the extent of the Significant Impact Area (SIA) of the proposed project is to be determined.

Table 5-6: Summary of Significant Impact Levels and Related Significant Areas

Pollutant	Averaging Time	PSD Class II SIL ($\mu g/m^3$)	Screening Model Max. SIA (kilometers)
Nitrogen Dioxide (NO_2)	Annual	1	50.0
Particulate Matter ($PM_{2.5}$)	24-hour Annual	NA NA	NA NA
Particulate Matter (PM_{10})	24-hour Annual	5 1	18.8 2.8
Sulfur Dioxide (SO_2)	3-hour 24-hour Annual	25 5 1	Impact not significant 29.8 Impact not significant
Carbon Monoxide (CO)	1-hour 8-hour	NA NA	NA NA

SIL Significant Impact Level
SIA Significant Impact Area
NA not applicable

Initially, the SIA is determined for every relevant averaging time for a particular pollutant. The final SIA for that pollutant is the largest area for each of the various averaging times. According to the EPA's Draft New Source Review Workshop Manual (EPA, 1990), the SIA is a circular area with a radius extending from the source to: (1) the most distant point where approved dispersion modeling predicts a significant ambient impact will occur, or (2) a modeling receptor distance of 50 kilometers, whichever is less. Therefore, a SIA cannot be greater than 50 kilometers for any pollutant. From Table 5-6, the SIAs for NO_2, PM_{10}, and SO_2 are 50, 18.8, and 29.8 kilometers, respectively.

The full impact analysis expands the preliminary impact analysis by considering emissions from both the proposed project as well as other sources in the SIA (the competing sources). The full impact analysis may also consider other sources outside the SIA that could cause significant impacts in the SIA of the proposed source. The results from the full impact analysis are used to demonstrate compliance with NAAQS and PSD increments. The source inventory for the cumulative NAAQS analysis includes all nearby sources that have significant impacts within the proposed source SIA, while the source inventory for the cumulative PSD increment analysis is limited to increment-affecting sources (new sources and changes to existing sources that have occurred since the applicable increment baseline date).

The full impact analysis is limited to receptor locations within the proposed project's SIA. The modeling results from the NAAQS cumulative impact analysis are added to representative ambient background concentrations, and the total concentrations are compared to the NAAQS. However, the modeled air quality impacts for all increment-consuming sources are directly compared to the PSD increments to determine compliance (without consideration of ambient background concentrations).

5.8 Nearby Sources

For any pollutant, the *Discoverer's* maximum predicted SIA, using conservative screening modeling, is 50 kilometers. The *Discoverer* is to be used for exploratory drilling activity at Shell's Burger Prospect oil and gas lease blocks (Figure 1-1) which is over 90 kilometers offshore. Because of the remote offshore location of the Shell leases and the lack of any significant nearby sources, impacts from other sources (e.g., competing sources) were not considered in the impact analysis. Per EPA's request, Alaska DEC was contacted and confirmed that there are no other competing sources near the Shell project.[55] Therefore, the maximum predicted concentrations from only the *Discoverer* activities on the Chukchi OCS are added to the ambient baseline concentrations (described in Section 6) for comparison to the NAAQS and the PSD increment. Emissions of lead are insignificant and were not evaluated.

5.9 Selection of Drilling Locations to Determine Worst-Case Cumulative Impacts

It is impossible to terminate one well site operation and move, set anchors, and commence operation on a second well on the same day, so additive short-term impacts (i.e., combined impacts of 24 hours or less) from two sequential *Discoverer* wells cannot exist. On the other hand, it is possible that annual impacts could be additive from the *Discoverer* drilling sequentially at different locations.

Additive annual impacts are addressed by including the impacts from a first drill site lasting 84 days and a second drill site that is drilled at a minimum distance from the first drill site of 1,000 meters and upwind, for another 84 days. Shell has offered this 1,000-meter minimum drill site separation distance (in any drill season) as a permit restriction (ORR). It is possible for the *Discoverer* to drill at more than two drill sites in the same drilling season. In these cases, all drill sites would be separated by at least 1,000 meters and the total duration of drilling of the first, second, third, fourth drill site and so on summed could not be greater than a maximum 168-day season. Maximum impacts would involve one drill site being drilled for, hypothetically, 84 days and the impacts would be at the downwind edge of the safety and equipment protection exclusion zone, supplemented by the impacts of the additional drill sites, all of which would be at a distance of at least 1,000 meters and also upwind of the receptor of maximum impact from the first drill site, as shown on Figure 5-2. Thus, both Cases A and B shown in Figure 5-2 will result in the same worst-case impact value. In both of these cases, the maximum impacts from one drill site added to the maximum impacts from a second drill site (separated by 1,000 meters) will

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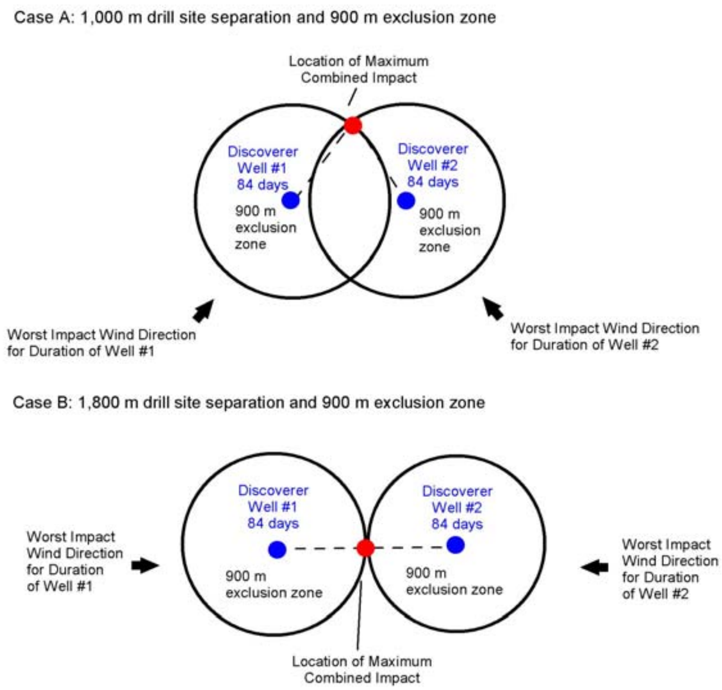
55 Schuler, Alan, Alaska DEC [Communications with T. Martin, Air Sciences Inc.]. January, 26, 2009.

result in the worst-case impact for two drill sites. In both cases, the impacts from both drill sites overlap at the ambient air boundary of at least 900 meters. For this to occur, the predominant wind pattern would need to shift up to 180 degrees between the well drillings, which is an absurd combination of assumptions, but is the nature of a screening analysis that provides an impact estimate below which the maximum actual impact will be. Since all of those additional drill sites together could have emissions lasting no more than 84 days combined, the impacts of those additional drill sites would be no greater than the impact from only a second drill site being drilled for 84 days. So, the highest impact of any undefined number of drill sites drilled would be equal to the two-drill site scenario with the drill sites separated by 1,000 meters. This is the scenario that is used to define the maximum screening impacts, which will necessarily exceed the real maximum impacts. Additionally, the worst-case maximum additive annual impact occurs at a unique point at which, under the annual average standard (chronic exposure), a member of the public is assumed to remain located for the entire duration of the drilling of two or more wells, which, of course, will not happen.

Figure 5-2: The Maximum Annual Impact Configuration for Sequential Drill Sites



5.10 Post-Processing of the Impacts to Incorporate Annual Operating Restrictions into the Impacts

Shell proposes several long-term (seasonal) owner-requested restrictions to restrict the use of the MLC compressors and HPUs to the equivalent of capacity operation for 48 days per season, and the ice management ships to the equivalent of capacity operation for 64 days (38 percent of a 168-day season) per season. The resupply ship is expected to be used only a few days per season. To account for these reduced usages, it is assumed that all are modeled as emitting for no more than 32 days per 84-day period and the following modeling approach is utilized. First, the model is run with all sources included and then the 1-hour impacts are post-processed by multiplying by the persistence factor (Table 5-3) and adjusting impacts by 32 days/365 days. Then the model is run with all sources except the HPU engines, air compressors, resupply vessel, OSR fleet, and ice management fleets (called the "No xxd" model runs) and then post-processed by multiplying by the persistence factor and adjusting impacts by (84 days - 32 days)/365 days.

When these impacts are added together on a receptor-by-receptor basis, effectively 32 days of the ORR sources are accounted for while 84 days of operations of all other sources are accounted for. This approach considers the worst-case meteorological condition at each receptor for both sets of model runs while also maintaining spatial relationships to allow for a more realistic pattern of dispersion from the sources emitting together as a group. The sum of the two model runs for each pollutant represents the maximum combined impact from two drill sites.

SECTION 6

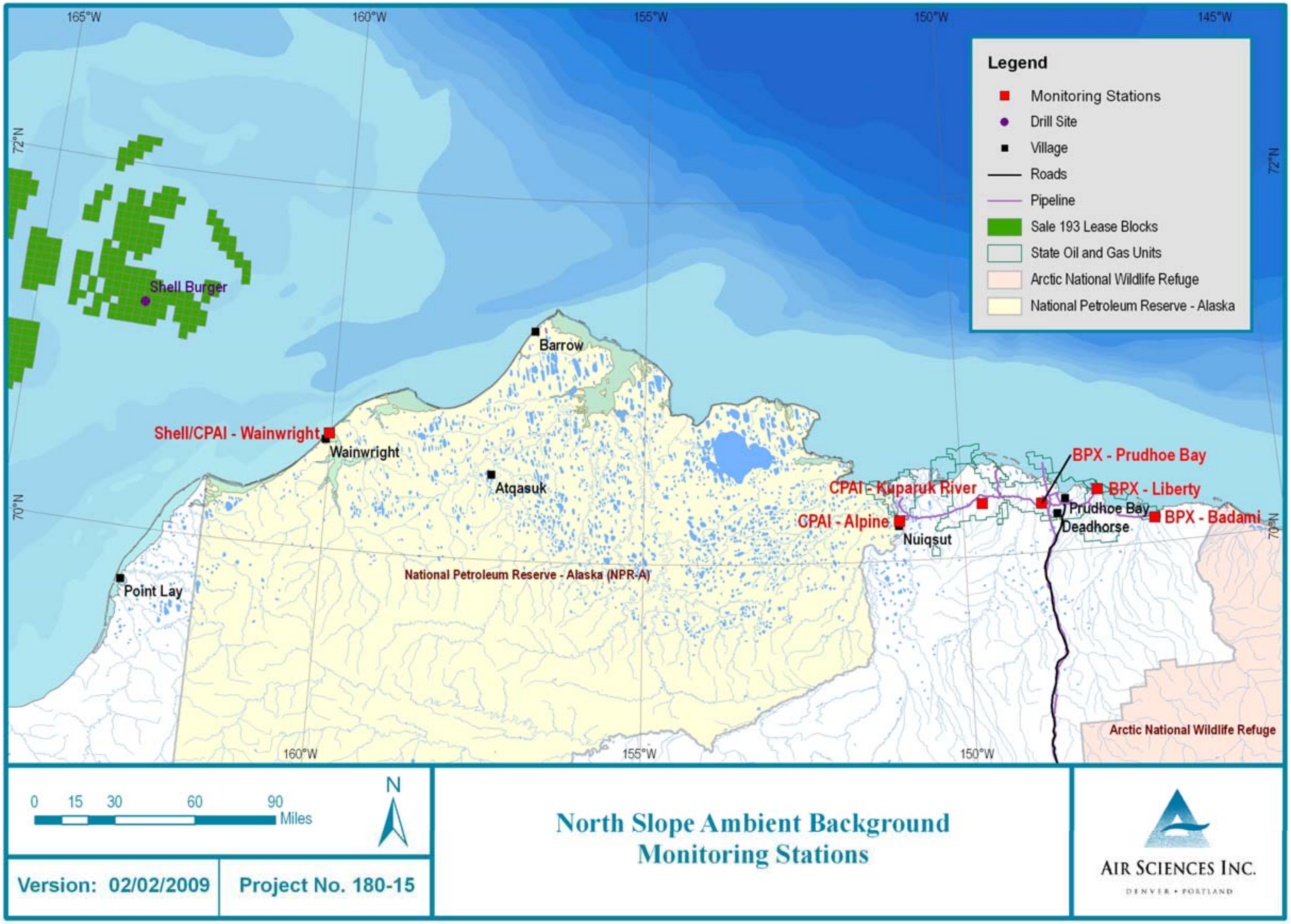
BASELINE CONCENTRATIONS

When comparing a project's impact to the NAAQS, an ambient background concentration is needed. The background concentration represents impacts from natural and anthropogenic sources not included in the impact modeling analysis. The Shell Burger Prospect drill site location on the Alaska OCS will be far (90 kilometers) from the Alaska shoreline and away from significant sources of pollution so that existing air quality concentrations can be represented with a regional value. According to the Guideline on Air Quality Models (40 CFR 51, Appendix W, Section 8.2.2c), if there are no monitors located in the vicinity of the source, a "regional site" may be used to determine background concentrations. A "regional site" is one that is located away from the area of interest, but is impacted by similar natural and distant man-made sources. Shell asserts that the data collected as part of both BP's Arctic North Slope Eastern Region (ANSER) monitoring program (near the BP Badami facility in 1999) and the Shell/CPAI Wainwright monitoring program represent regional background concentrations. While the Badami data sets are more than three years old, there has been little or no industrial or residential growth within a 25-kilometer radius of this station since the data were collected that would make these data sets unrepresentative of present-day conditions.

Shell and CPAI began monitoring NO_2, $PM_{2.5}$, PM_{10}, SO_2, CO, and O_3 concentrations at Wainwright, Alaska in November 2008. The Wainwright and Badami monitoring stations are both remotely located (minimal influence of industry and other human activities) and are the most representative "regional sites" on the North Slope for estimating offshore monitoring concentrations. A map of the ambient monitoring stations on the North Slope is provided in Figure 6-1. Shell utilizes available Wainwright monitoring data (beginning in November 2008 through December 2008) to demonstrate that the ANSER baseline data are in-fact regionally representative (or higher than) the Chukchi Sea. Shell will submit Wainwright ambient data through April 2009 to verify that the Badami data set is representative of the Wainwright and Chukchi baseline. Impact modeling results in Section 7 show that with these estimates of baseline the NAAQS are met and that even with a significant increase, the standards would still be met.

Because Badami is a regional site with an entire year of data, Shell utilizes the maximum measured concentrations from both the Wainwright station and Badami station to represent Chukchi Sea baseline concentrations.

Figure 6-1: Map of Ambient Monitoring Stations on the North Slope



Per the quality assurance plan for the Wainwright monitoring program,[56] the Wainwright monitoring station is located in a relatively pristine area. The Wainwright power plant, to the north, and the water treatment plant, to the west, are the largest single stationary sources in the area. Collectively, emissions from fuel-oil fired home heating within the community also contribute a significant amount of emissions to the local airshed. The Search and Rescue Headquarters building, from which the Wainwright sampling is being conducted, has two fuel-oil fired heaters and no other combustion sources. Special care is being taken to locate sample inlets as far away as possible from these sources, and generally upwind of them. However, it is anticipated that impacts from these sources may be measured from time to time. Data collected that is known to be impacted by emissions from the Search and Rescue Headquarters building will be flagged prior to reporting. Shell will also flag hours which are obviously influenced by naturally occurring wildfires as these values are not representative of typical ambient background concentrations. If these local sources have any impact on the station, they would tend to elevate the Wainwright data. Therefore, this station provides an upper bound on the Chukchi baseline concentrations.

The Wainwright data (November 2008 – December 2008) collected prior to the final modeling analysis will not include calendar quarter #3 (July, August, September), so available North Slope monitoring data has been reviewed to demonstrate that non-summer values at Wainwright can be used to conservatively represent background concentrations.

Figures 6-2, 6-3, and 6-4 provide a quarterly breakdown of average monthly NO_2 concentrations, average maximum 3-hour SO_2 concentrations, and average maximum 24-hour SO_2 concentrations at all monitoring locations on the North Slope. From these figures, it is evident that gaseous pollutant concentrations are highest in the wintertime months (Q1, Q4) and lowest in the summer months (Q3).

There are three stations on the North Slope that monitor CO (Wainwright, BPX – Liberty, and CPAI – Kuparuk River). Hourly CO data is only available from Alaska DEC for the BPX – Liberty station and is provided in Figure 6-5. A review of hourly data from BPX – Liberty indicates that CO concentrations are generally higher in the wintertime months and lower in the summertime months with the exception of an abnormal spike in mid-September, 2007. This spike was caused by naturally occurring wildfires and is not representative of typical ambient background concentrations. In mid-September 2007, a large, 250,000 acre wild fire was burning to the south of the Prudhoe Bay area which elevated pollutant levels on the North Slope.[57] Even during this fire episode, the highest measured CO concentration at BPX – Liberty (highest on North Slope) was still only 4.3% of the 1-hour NAAQS value.

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[56] Conoco Phillips Alaska, Inc., *Wainwright Near-Term Ambient Air Quality Monitoring Quality Assurance Project Plan prepared by ENSR Corporation. Document No.: 01865-100-2100.* November 2008.

[57] U.S. Department of Interior, Bureau of Land Management. *Wildland Fire Dataset for Alaska*. http://agdc.usgs.gov/data/blm/fire/index.html

Therefore, higher concentrations of pollutants, primarily resulting from combustion related activities (i.e., NO_2, SO_2, CO and $PM_{2.5}$), are highest in the wintertime when atmospheric conditions are more stable, dispersion is poorer, and residential heating emissions (e.g., wood smoke, fuel-oil heaters, etc.) are higher. Utilization of Wainwright data collected during the wintertime months will provide conservative background concentrations for offshore locations.

Figure 6-2: Average Monthly NO_2 Concentrations for North Slope Stations

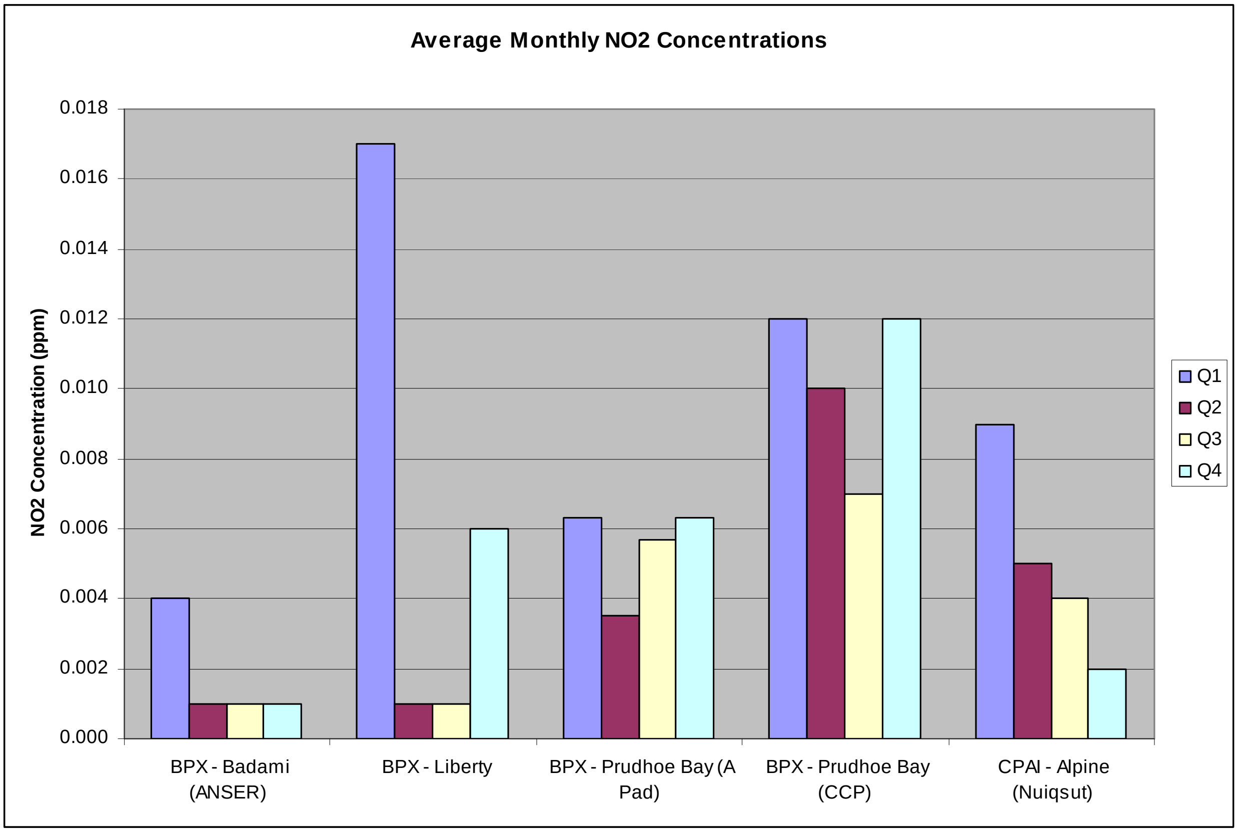


Figure 6-3: Average Maximum 3-Hour SO_2 Concentrations for North Slope Stations

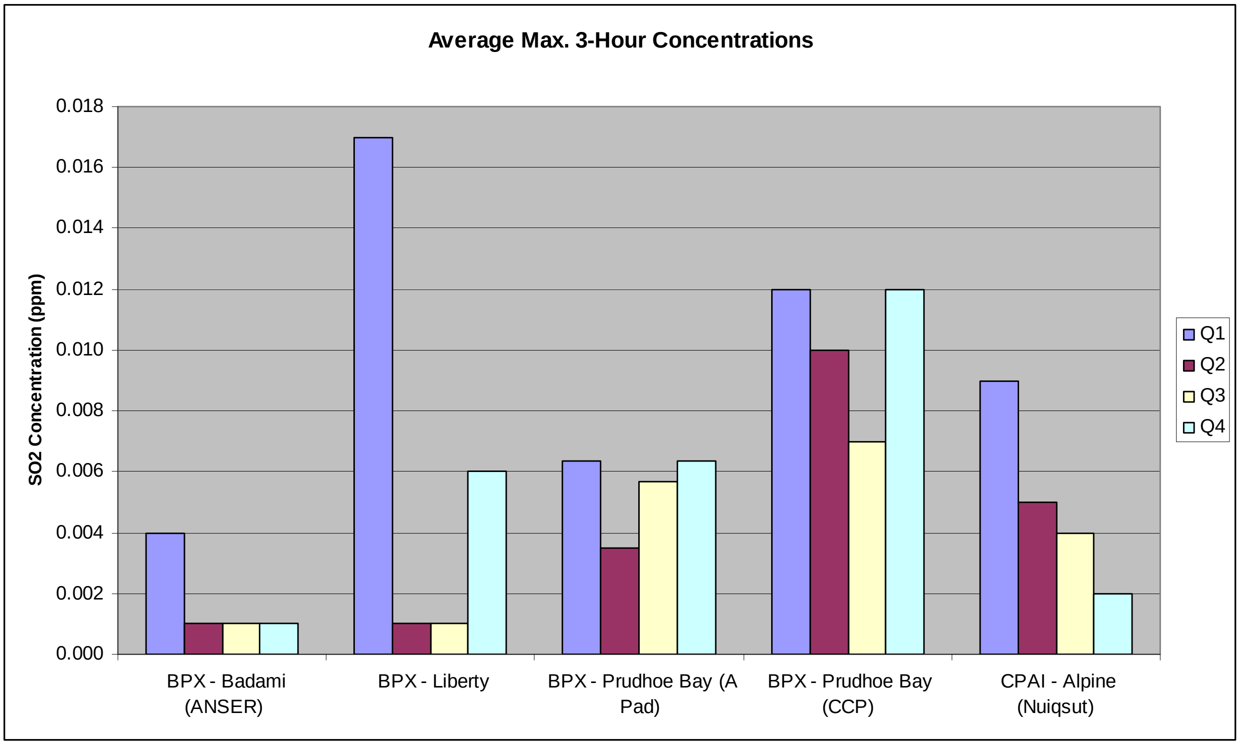


Figure 6-4: Average Maximum 24-Hour SO_2 Concentrations for North Slope Stations

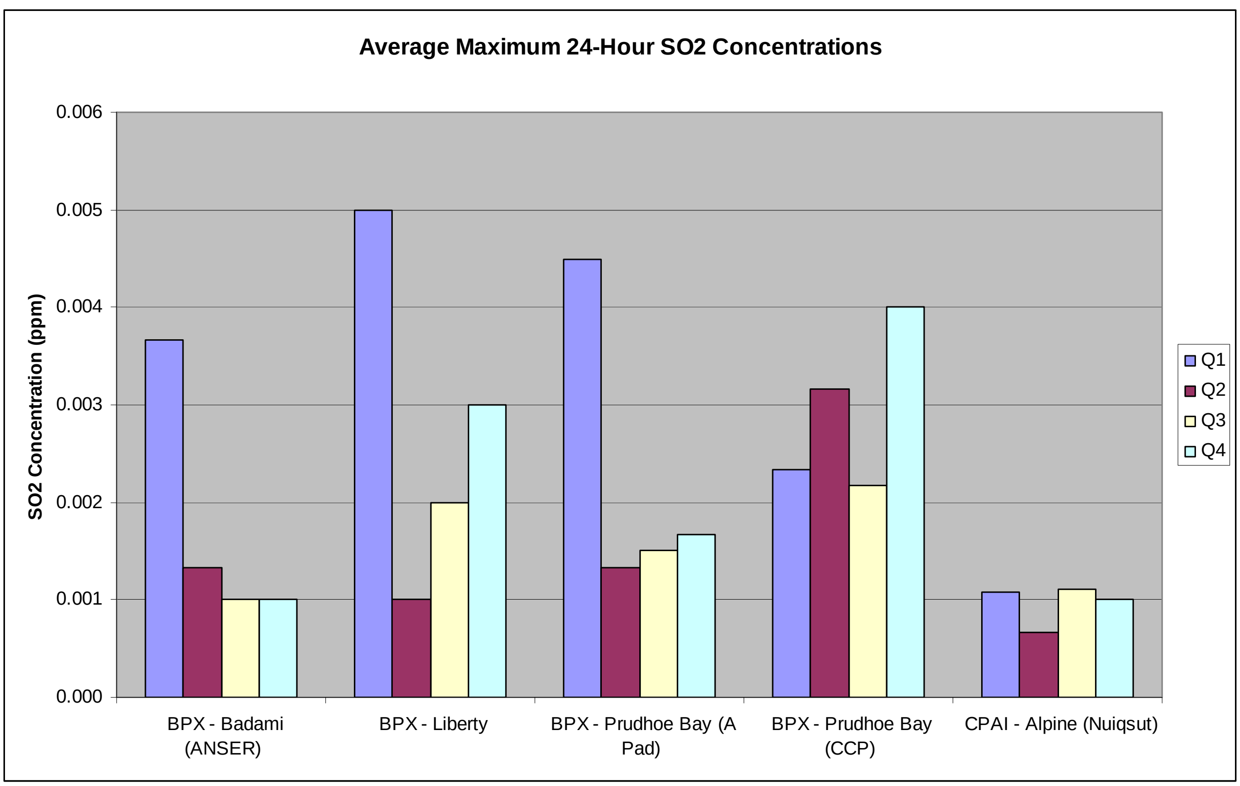
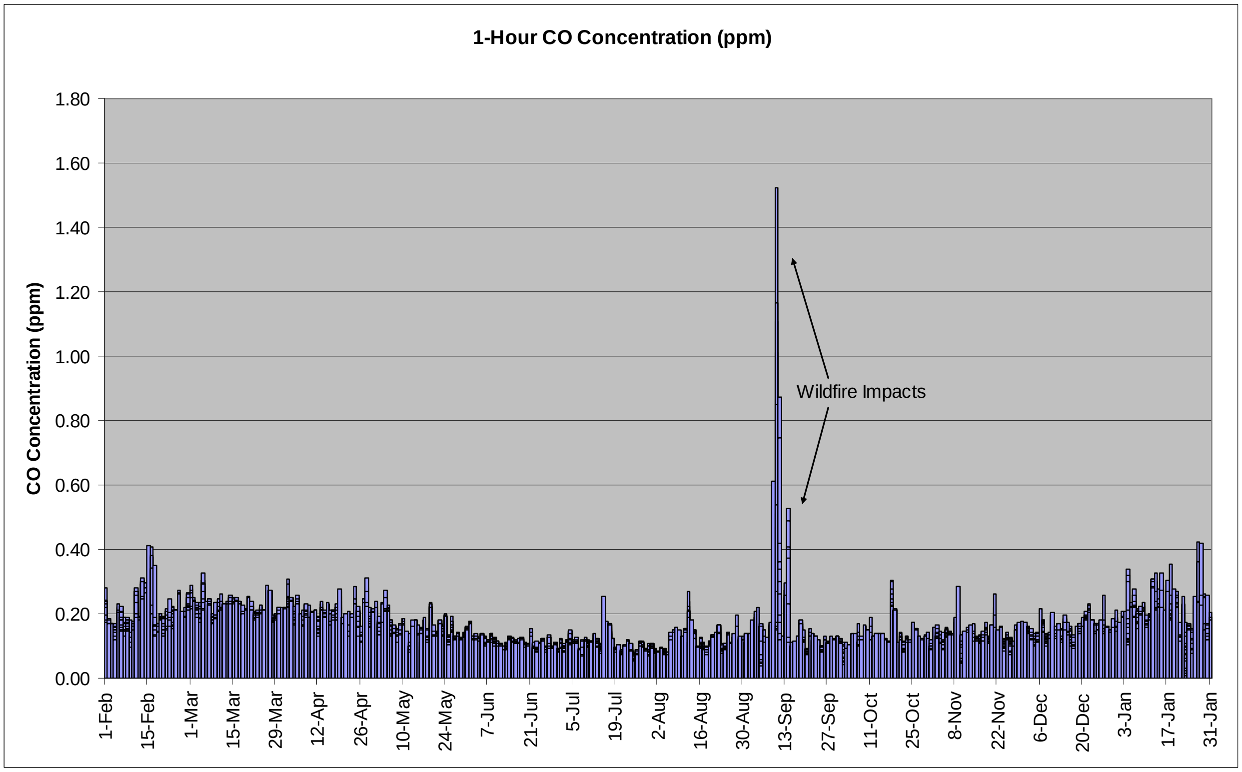


Figure 6-5: Time Series of 1-Hour CO Concentrations at BPX - Liberty



Measured PM_{10} concentrations are locally effected by emission sources such as blowing dust from river channels, fugitive emissions from nearby roads, etc. The Wainwright and Badami stations are assumed to be minimally impacted by fugitive sources of PM_{10} emissions compared to other North Slope stations such as Nuiqsut which is sited close to loess-rich Colville River channels, where clay-sized material easily becomes airborne when dry.

Table 6-1 shows the seasonal breakdown of PM_{10} measurements at Badami. At Badami, there is a bi-modal PM_{10} distribution where impacts are higher in both the wintertime (Q1) and the summertime (Q3) and lower in the fall and spring. The summertime PM_{10} concentrations at Badami are influenced by locally generated dust sources associated with drier soil/road conditions and human activities at the Badami facility and the nearby Badami airport.

Table 6-1: Seasonal PM_{10} Concentrations at Badami

	PM_{10} Concentration (ug/m^3)	
Quarter	Max. 24-Hour	Quarter Avg.
Q1	9.5	2.6
Q2	5.5	1.5
Q3	12.4	2.8
Q4	6.4	1.4

The Shell project will be remotely located over open water and away from land-based sources of dust and other combustion-related activities. There is no industry on the Chukchi Sea coast within 90 kilometers of the Burger site location in the Chukchi Sea. Without local crustal and combustion-related sources, maximum offshore concentrations are expected to occur in the wintertime under stable atmospheric conditions. Wintertime measurements at Wainwright and year-round measurements at Badami are available and the highest values (excluding hours influenced by wildfires) from these two regional datasets provide a conservative estimate of offshore ambient background concentrations for Shell's proposed project location and drilling season.

Table 6-2 provides a representative estimate of regional background concentrations in remote locations of the Alaska OCS where there are no significant pollution sources. The Wainwright monitored concentrations will be updated with data through April 2009 for verification of the results herein.

Table 6-2: Baseline Concentrations

		Monitored Concentrations		
Pollutant	Averaging Time	Badami[1] (µg/m³)	Wainwright[2] (µg/m³)	Maximum (µg/m³)
NO_2	Annual	3	2	3
$PM_{2.5}$	24-hour	N/A	9	5
	Annual	N/A	2	2
PM_{10}	24-hour	12	9	12
	Annual	2	---	2
SO_2	3-hour	18	18	18
	24-hour	16	10	16
	Annual	3	---	3
CO	1-hour	N/A	896	896
	8-hour	N/A	514	514

[1] Based on BP's Arctic North Slope Eastern Region (ANSER) monitoring program, which took place east of BP's Badami facility in 1999.

[2] Wainwright data provided is preliminary data for November and December 2008; values to be updated as more data becomes available.

NA Not applicable

SECTION 7

IMPACT MODELING RESULTS

7.1 Worst-Case Concentration Impacts

The *Discoverer* drilling impact summary of Table 7-1 is developed from the individual source impacts and background concentrations (for NAAQS) for all applicable averaging times. Because this two-drill site scenario defines the worst-case annual impact, Shell's Chukchi Sea exploratory drilling program will comply with the NAAQS and PSD increments. The modeling results and associated calculations for the annual impacts are provided in Table 7-2. Results and associated calculations for both short-term and annual impacts are summarized in Table 7-3. All electronic modeling files and associated calculations are provided in the CD.

Table 7-1: Summary of Screening Maximum Estimated Short-Term and Annual Concentrations all Sources Combined

Pollutant	Averaging Time	NAAQS[1] (µg/m³)	Screening Model Max. Impact Plus Background[2] (µg/m³)	PSD Class II Increment (µg/m³)	Screening Model Max. Impact No Background[3] (µg/m³)
Nitrogen Dioxide (NO_2)	Annual	100	14.4	25	11.1
Particulate Matter ($PM_{2.5}$)	24-hour	35	31.6	NA	NA
	Annual	15	2.9	NA	NA
Particulate Matter (PM_{10})	24-hour	150	35.3	30	22.9
	Annual	50	3.4	17	1.4
Sulfur Dioxide (SO_2)	3-hour	1,300	35.8	512	17.6
	24-hour	365	26.2	91	10.6
	Annual	80	3.1	20	0.5
Carbon Monoxide (CO)	1-hour	40,000	1,025.9	NA	NA
	8-hour	10,000	631.2	NA	NA

[1] National Ambient Air Quality Standards

[2] Maximum modeled impacts plus background concentrations are compared to the NAAQS.

[3] Maximum modeled impacts only (no background concentrations included) are compared to the PSD Increments.

NA Not applicable

Table 7-2: Impact Scenarios Used to Define Screening Maximum Annual Impacts from All Sources and Multiple Sequential Wells

Pollutant	Model Run	Impact Category	Max. Impact Location X(m)	Max. Impact Location Y(m)	Modeled 1-Hour Impact [2]	Persistence Factor	Emis. Adjust [3]	Conc. (µg/m³)
NO_2 [4]	All Sources	900 m from Rig [1]	-884.3	55	637.9	0.10	0.0877	4.2
	No xxd [2]	900 m from Rig [1]	-884.3	55	125.7	0.10	0.1425	1.3
	All Sources	900 m from Rig [1]	-884.3	55	637.9	0.10	0.0877	4.2
	No xxd [2]	900 m from Rig [1]	-884.3	55	125.7	0.10	0.1425	1.3
							Total Annual NO_2 Impact (µg/m³) [5] >	*11.1*

Pollutant	Model Run	Impact Category	Max. Impact Location X(m)	Max. Impact Location Y(m)	Modeled 1-Hour Impact [2]	Persistence Factor	Emis. Adjust [3]	Conc. (µg/m³)
PM_{10} &	All Sources	900 m from Rig [1]	-884.3	55	38.1	0.10	0.0877	0.3
$PM_{2.5}$	No xxd [2]	900 m from Rig [1]	-884.3	55	26.9	0.10	0.1425	0.4
	All Sources	900 m from Rig [1]	-884.3	55	38.1	0.10	0.0877	0.3
	No xxd [2]	900 m from Rig [1]	-884.3	55	26.9	0.10	0.1425	0.4
							Total Annual PM_{10} and $PM_{2.5}$ Impact (µg/m³) [5] >	*1.4*

Pollutant	Model Run	Impact Category	Max. Impact Location X(m)	Max. Impact Location Y(m)	Modeled 1-Hour Impact [2]	Persistence Factor	Emis. Adjust [3]	Conc. (µg/m³)
SO_2	All Sources	900 m from Rig [1]	-884.3	55	17.4	0.10	0.0877	0.2
	No xxd [2]	900 m from Rig [1]	-884.3	55	8.2	0.10	0.1425	0.1
	All Sources	900 m from Rig [1]	-884.3	55	17.4	0.10	0.0877	0.2
	No xxd [2]	900 m from Rig [1]	-884.3	55	8.2	0.10	0.1425	0.1
							Total Annual SO_2 Impact (µg/m³) [5] >	*0.5*

Assume 84 days per drilling location and 32 days of operation for HPU engines, air compressors, and resupply, ice management, and OSR ships at each location.

[1] Assume that the minimum separation distance between drilling locations is 1,000 meters and that there is at least a 900-meter ambient air boundary for annual impacts.

Assume two drilling locations for annual impacts (i.e., 84-day duration at each drilling location during a 168-day drilling season).

[2] For each drill site, modeled 1-hour impacts for both sets of model runs (i.e., A) all sources and B) no HPUs, compressors, and resupply, ice management, or OSR ships (also call "No xxd" model run) which results in the highest combined impact after emissions adjustments are made.

[3] Annual emissions adjustment to modeled hourly emissions to account for duration at each drill site. Model run with all sources is adjusted by 32 days/365 days (i.e., 0.0877) and model run with no HPUs, compressors, and resupply, ice management, or OSR ships is adjusted by (84 days - 32 days)/365 days (i.e., 0.1425).

[4] Assume that $NO_2 = NO_x * 0.75$.

[5] Total modeled impact (without background) is the sum of the impacts at or beyond at least a 900 ambient air boundary of the *Discoverer* plus the impacts at or beyond 900 meters (for annual impacts only).

Table 7-3: Combined Screening Maximum Impacts from All Sources and Multiple Sequential Wells

Pollutant	Averaging Period	Max. Modeled 1-Hour Impact 900 m	Persistence Factor	Emis. Adj. [2]	Concentration (μg/m³) Hole #1 Impact at or beyond 900 m [1]	Hole #2 Impact at or beyond 900 m [1]	Background	Total No Background [4]	Total w/ Background [5]	PSD Class II Increment (μg/m³)	Comply?	NAAQS (μg/m³)	Comply?	Sig. Monitoring Conce. (μg/m³)	Exceed?
NO_2 [3]	Annual	See Calculations in Table 7-2			5.5	5.5	3.3	11.1	14.4	25	Yes	100	Yes	14	No
$PM_{2.5}$	24-Hour	38.1	0.6	1	22.9	---	8.7	22.9	31.6	---	---	35	Yes	---	---
	Annual	See Calculations in Table 7-2			0.7	0.7	1.5	1.4	2.9	---	---	15	Yes	---	---
PM_{10}	24-Hour	38.1	0.6	1	22.9	---	12.4	22.9	35.3	30	Yes	150	Yes	10	Yes
	Annual	See Calculations in Table 7-2			0.7	0.7	2.0	1.4	3.4	17	Yes	50	Yes	---	---
SO_2	3-Hour	17.6	1.0	1	17.6	---	18.2	17.6	35.8	512	Yes	1,300	Yes	---	---
	24-Hour	17.6	0.6	1	10.6	---	15.6	10.6	26.2	91	Yes	365	Yes	13	No
	Annual	See Calculations in Table 7-2			0.3	0.3	2.6	0.5	3.1	20	Yes	80	Yes	---	---
CO	1-Hour	129.8	1.0	1	129.8	---	896.1	129.8	1,025.9	---	---	40,000	Yes	---	---
	8-Hour	129.8	0.9	1	116.8	---	514.4	116.8	631.2	---	---	10,000	Yes	575	No

Assume 84 days per drilling location and 32 days of operation for HPU engines, air compressors, cranes, and resupply, ice management, and OSR ships at each location.

1 Assume that minimum separation distance between drilling locations is 1,000 meters and that there is a 900-meter safety exclusion zone for annual impacts.
Assume two drilling locations for annual impacts (i.e., 84-day duration at each drilling location during a 168-day drilling season).
Short-term impacts are adequately addressed with one drilling location.

2 Annual emissions adjustment to modeled hourly emissions; assume 84 days per location and the HPU engines, air compressors, and resupply, ice management, and OSR ships are limited to 32 days per location. Short-term emissions are not adjusted since 24 hour/day operations are considered.

3 Assume that $NO_2 = NO_x * 0.75$.

4 Total modeled impact without background is the sum of the maximum impact at the or beyond at least a 900-meter ambient air boundary from the *Discoverer* and the impact at or beyond 900 meters (for annual impacts only).

5 Total modeled impact without background is the sum of the maximum impact at or beyond at least a 900-meter ambient air boundary of the *Discoverer*, the impact at or beyond 900 meters (for annual impacts only), and background concentrations.

Note that the worst-case impacts in Table 7-3 are also compared to the significant monitoring concentration thresholds. For any criteria pollutant that Shell proposes to emit in significant quantities, continuous monitoring data may be required as part of the air quality analysis. The permitting agency has discretionary authority to exempt a permit applicant from this data requirement if, 1) the highest modeled ambient impacts, or 2) the existing ambient pollutant concentrations are less than the significant monitoring concentration listed in Table 7-3. Both existing ambient background PM_{10} concentrations and maximum modeled impacts exceed the significant monitoring thresholds. The ambient background concentration of SO_2 exceeds the significant monitoring thresholds, but not the maximum modeled impacts. As part of the Wainwright monitoring program, these pollutants along with other criteria pollutants are being gathered for use in the ambient impact analysis.

7.2 Source Contribution Analyses at Maximum Impact Location

EPA has asked that Shell provide a breakdown of individual source contributions. A source contribution analysis for 24-hour average PM_{10} (and $PM_{2.5}$) and annual average NO_2 is provided in Table 7-4. These pollutants and averaging times are presented since these are the highest impacts relative to the applicable ambient standards. Maximum impacts for annual NO_2 are driven by poorer dispersing engines (HPU engines and cementing units) on the *Discoverer* while 24-hour PM_{10} impacts are dominated by the incinerator on the *Discoverer*.

Table 7-4: Discoverer Source Contributions at the Screening Maximum Impact Locations

Source Description	Model Source ID	Impact Contribution (%) [1]	
		Annual NO_2	24-Hour PM_{10}
Stack #1: 6 Main Drill Engines	MAINENGS	1	1
Stack #2: 2 Air Compressors	COMPENGS	3	3
Stack #3: 2 HPU Engines	HPPENGS	24	10
Stack #4: 3 Cementing Units	CEMENT	28	5
Stack #5a: Crane Engine (port)	CRANE_PT	4	1
Stack #5b: Crane Engine (stbd)	CRANE_SB	15	4
Stack #6: 2 Heat Boilers	HEATBOIL	7	7
Stack #7: 1 Incinerator	INCIN_D	3	57
Resupply Ship	KILABUK	1	1
Oil Spill Response Ships	OILSPL01-40	0	0
Ice Management (Secondary)	BRK_B01-48	10	7
Ice Management (Primary)	BRK_A01-96	5	4
	Total >	100	100

[1] Maximum impacts occur on the 900 meter ambient air boundary directly downwind of the *Discoverer*. Maximum impact receptor is -884.3, 55.0 and impact date is 01050412 (yymmddhh).

7.3 Impacts from the Ice Management and Anchor Handler Fleet

EPA has asked that Shell provide a table showing the maximum concentration impacts from both the primary and the secondary ice management ships and its locations. As expected, if the impacts from all source operations show compliance with the ambient standards as shown in Table 7-3 above, then the impacts from each of the ice management ships individually will also be less than the ambient standards. The maximum impacts from the primary ice management fleet and secondary ice management fleet are provided below in Table 7-5 and 7-6, respectively, and impacts are well below the PSD increment and NAAQS thresholds.

Table 7-5: Maximum Impacts from Primary Ice Management Ship

Pollutant	Averaging Period	Coordinate of Max. Impact Receptor X (m)	Coordinate of Max. Impact Receptor Y (m)	Max. Modeled 1-Hr Impact (µg/m³)	Persistence Factor	Emission Adjustment [1]	Concentration (µg/m³) Max. Modeled Impact (µg/m³)	Concentration (µg/m³) Background	Concentration (µg/m³) Total No Background	Concentration (µg/m³) Total w/ Background	PSD Class II Increment [2] (µg/m³)	PSD Class II Increment [2] Comply?	NAAQS [3] (µg/m³)	NAAQS [3] Comply?
NO_2	Annual	4,800.0	-4,500.0	78.3	0.1	0.1753	1.0	3.3	1.0	4.3	25	Yes	100	Yes
$PM_{2.5}$	24-Hour	4,800.0	-4,500.0	2.5	0.6	1	1.5	8.7	1.5	10.2	---	---	35	Yes
	Annual	4,800.0	-4,500.0	2.5	0.1	0.1753	0.04	1.5	0.04	1.5	---	---	15	Yes
PM_{10}	24-Hour	4,800.0	-4,500.0	2.5	0.6	1	1.5	12.4	1.5	13.9	30	Yes	150	Yes
	Annual	4,800.0	-4,500.0	2.5	0.1	0.1753	0.04	2.0	0.04	2.0	17	Yes	50	Yes
SO_2	3-Hour	4,800.0	-4,500.0	5.0	0.9	1	4.5	18.2	4.5	22.7	512	Yes	1,300	Yes
	24-Hour	4,800.0	-4,500.0	5.0	0.6	1	3.0	15.6	3.0	18.6	91	Yes	365	Yes
	Annual	4,800.0	-4,500.0	5.0	0.1	0.1753	0.1	2.6	0.1	2.7	20	Yes	80	Yes
CO	1-Hour	4,800.0	-4,500.0	20.8	1.0	1	20.8	896.1	20.8	916.9	---	---	40,000	Yes
	8-Hour	4,800.0	-4,500.0	20.8	0.9	1	18.7	514.4	18.7	533.1	---	---	10,000	Yes

[1] For short-term impacts assume 24-hour day operations (adjustment = 1) for annual impacts assume 64 days per drilling season (adjustment = 64 days/365 days).
[2] Impacts without background concentrations are compared to the PSD increments.
[3] Impacts including background concentrations are compared to the NAAQS.

Table 7-6: Maximum Impacts from Secondary Ice Management Ship

Pollutant	Averaging Period	Coordinate of Max. Impact Receptor X (m)	Y (m)	Max. Modeled 1-Hr Impact (μg/m³)	Persistence Factor	Emission Adjustment [1]	Concentration (μg/m³) Max. Modeled Impact (μg/m³)	Background	Total No Background	Total w/ Background	PSD Class II Increment [2] (μg/m³)	Comply?	NAAQS [3] (μg/m³)	Comply?
NO_2	Annual	976.1	-331.6	177.9	0.1	0.1753	2.3	3.3	2.3	5.6	25	Yes	100	Yes
$PM_{2.5}$	24-Hour	976.1	-331.6	5.7	0.6	1	3.4	8.7	3.4	12.1	---	---	35	Yes
	Annual	976.1	-331.6	5.7	0.1	0.1753	0.1	1.5	0.1	1.6	---	---	15	Yes
PM_{10}	24-Hour	976.1	-331.6	5.7	0.6	1	3.4	12.4	3.4	15.8	30	Yes	150	Yes
	Annual	976.1	-331.6	5.7	0.1	0.1753	0.1	2.0	0.1	2.1	17	Yes	50	Yes
SO_2	3-Hour	976.1	-331.6	11.3	0.9	1	10.2	18.2	10.2	28.4	512	Yes	1,300	Yes
	24-Hour	976.1	-331.6	11.3	0.6	1	6.8	15.6	6.8	22.4	91	Yes	365	Yes
	Annual	976.1	-331.6	11.3	0.1	0.1753	0.2	2.6	0.2	2.8	20	Yes	80	Yes
CO	1-Hour	976.1	-331.6	47.3	1.0	1	47.3	896.1	47.3	943.4	---	---	40,000	Yes
	8-Hour	976.1	-331.6	47.3	0.9	1	42.5	514.4	42.5	556.9	---	---	10,000	Yes

[1] For short-term impacts assume 24-hour day operations (adjustment = 1) for annual impacts assume 64 days per drilling season (adjustment = 64 days/365 days).

[2] Impacts without background concentrations are compared to the PSD increments.

[3] Impacts including background concentrations are compared to the NAAQS.

7.4 Worst-Case Screening Impacts at Nearest Villages on Chukchi Coast

Based on Figure 1-1, the nearest coastal villages to the existing Shell leases are Wainwright and Point Lay, which are approximately 110 and 100 kilometers away from the nearest Shell leases, respectively. Worst-case impacts from the proposed project using the screening analysis are provided in Table 7-7 and are well below the NAAQS, PSD increments, and significant concentrations. Impacts from the proposed project at these locations are lower than the measured background concentrations (existing air quality levels) representative of these pristine areas.

Table 7-7: Worst-Case Screening Impacts at Nearest Villages on Chukchi Coast

Pollutant	Averaging Period	Concentration ($\mu g/m^3$) Max. Modeled [1] Wainwright	Point Lay	Background	Total No Background	Total w/ Background	PSD Class II Increment [2] ($\mu g/m^3$)	Comply?	NAAQS [3] ($\mu g/m^3$)	Comply?	Shell Impact % NAAQS
NO_2	Annual	1.0	1.1	3.3	1.1	4.4	25	Yes	100	Yes	1
$PM_{2.5}$	24-Hour	1.7	1.8	8.7	1.8	10.5	---	---	35	Yes	5
	Annual	0.1	0.1	1.5	0.1	1.6	---	---	15	Yes	0.4
PM_{10}	24-Hour	1.7	1.8	12.4	1.8	14.2	30	Yes	150	Yes	1
	Annual	0.1	0.1	2.0	0.1	2.1	17	Yes	50	Yes	0.1
SO_2	3-Hour	4.5	4.8	18.2	4.8	23.0	512	Yes	1,300	Yes	0.4
	24-Hour	2.7	2.9	15.6	2.9	18.5	91	Yes	365	Yes	1
	Annual	0.1	0.1	2.6	0.1	2.7	20	Yes	80	Yes	0.1
CO	1-Hour	20.6	22.0	896.1	22.0	918.1	---	---	40,000	Yes	0.1
	8-Hour	18.6	19.8	514.4	19.8	534.2	---	---	10,000	Yes	0.2

[1] The nearest villages to Shell's Chukchi leases are Wainwright (~110 km away) and Point Lay (~100 km away).

[2] Total impact without background is compared to the PSD increments.

[3] Total impact with background is compared to the NAAQS.

SECTION 8

ADDITIONAL IMPACT ANALYSES

In addition to the NAAQS and PSD increment analyses, 40 CFR 52.21(o) requires that PSD applicants also address the impact from the proposed project on associated growth, soils and vegetation of significant commercial value impacts, and visibility impairment. EPA has also requested that Shell evaluate the proposed project's impact on ozone concentrations.

8.1 Growth Analysis

The specifics of expected secondary emissions associated with shoreline growth is addressed in Section 2.15 Because of the limited and temporary nature of the exploratory drilling program, indirect impacts on industrial, commercial, and residential growth will be insignificant. The emissions presented for the project already include all anticipated emissions, including those from support activities (e.g., resupply ships, ice management fleet, etc.). There will be no substantial increase in community growth needed to support the exploratory drilling program. Therefore, it is not anticipated that the project will result in more than a negligible increase in air emissions associated with growth.

8.2 Effects on Soils and Vegetation

According to the EPA's Draft New Source Review Workshop Manual (EPA, 1990), the analysis of air pollutant impacts on soils and vegetation is to be based on an inventory of soils and vegetation types found in the impact area. Permit applicants are not required to provide an analysis of the impact on vegetation having no significant commercial or recreational value. Because the drilling project will be located far offshore over open water, there are no soils or vegetation in the *Discoverer* project's SIAs (within 50 kilometers). Therefore, no further analysis is warranted.

8.3 Visibility Analysis

Visibility impacts can be in the form of visible plumes ("plume blight") or a general, area-wide reduction in visibility ("regional haze"). Visibility has been identified as an air quality-related value for the Alaska Class I areas as defined in the Clean Air Act (CAA). Impacts from new sources on Class I areas within 200 kilometers of a stationary source are of special concern to Federal Land Managers. The nearest Class I area (Denali National Park) is located more than 950 kilometers from the proposed exploratory drilling activities. In addition to this great distance, many sources associated with the exploratory drilling program are mobile and their plumes will be broken up and dispersed over large areas. The Brooks Range would break up any coherent plumes moving toward Denali National Park. Given these factors, the impacts to the nearest Class I area are considered insignificant and were not evaluated.

The EPA and the state of Alaska have not established visibility thresholds for Class II areas, and the exploratory program is located far offshore where any coherent plumes will be broken up and dispersed over large areas over water. In addition, there are no visibility or other special protection areas in Alaska (18 AAC 50.025) located near the project.

Visible plumes are nearly completely a result of PM emissions. The PM emissions from the *Discoverer* will be minimized through the use of oxidation catalysts and CDPFs on all on the diesel engines. It is possible that these engines will emit a visible plume during cold startup and these could last for several minutes. With the tailpipe control technology, these plumes should disappear quickly. There are expected to be some visible plumes in the near-field from emissions from the ice management and anchor handling fleet activity. However, given the mobile nature of these sources, plumes would be expected to be more coherent near the ice management and anchor handling ships and then the plumes would disperse and be broken up by movement of the ships and ambient winds.

The Clean Air Act established two types of national air quality standards, primary and secondary. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. Permitting authorities located in EPA Region 10 have utilized the secondary ambient air quality standards to address Class II visibility issues.[58] Therefore, for all Shell project sources, impacts to visibility are considered acceptable since the project's impacts are well below the secondary NAAQS for all pollutants.

8.4 Ozone Analysis

Because the proposed project's NO_x emissions exceed 100 tons per year, EPA has asked that Shell provide a qualitative discussion on ozone impacts. The Chukchi coastline nearest to the Shell project is part of the State of Alaska's Northern Alaska Intrastate Air Quality Control Region (40 CFR 81.246). This region is designated as attainment or unclassifiable for all criteria pollutants, including ozone (40 CFR part 81.302).

Shell began monitoring ozone concentrations at Wainwright, Alaska in November 2008. The nearest historical ozone monitoring stations to the Shell project are located on Alaska's North Slope as shown in Figure 8-1. Measured ozone concentrations at these monitoring stations, which are impacted by major oil and gas operations, are provided in Table 8-1. According to the U.S. Department of Energy, the Prudhoe Bay, Kuparuk River, and Alpine oil fields are ranked 1, 3, and 4, respectively, as the largest oil fields in the United States based on estimated oil

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58 Coburg Power, L.L.C. *Prevention of Significant Deterioration Permit Application – Coburg Power Generating Plant, Coburg, Oregon. Submitted to Lane Regional Air Pollution Authority*. February 2002.

production.[59] As shown in Table 8-1, the measured ozone concentrations in/near these large oil fields are all well below the ozone NAAQS.

Table 8-1: Maximum Measured Ozone Concentrations at North Slope Monitoring Stations

		Max. Monitored Ozone Concentration (ppb)	
Facility	Data Dates	1-Hour	8-Hour
Shell/CPAI - Wainwright	November 2008 [1]	35	34
Barrow - NOAA/GMD	2003, 2004, 2005 [2]	52	50
BPX - Badami	1999 [3]	48	48
BPX - Prudhoe Bay	2006, 2007 [3]	52	44
BPX - Prudhoe Bay	2006, 2007 [3]	73	43
CPAI - Alpine	Nov. 2004 - Dec. 2005 [3]	64	49
CPAI - Kuparuk River	June 2001 - June 2002 [3]	45	45 [4]
	Ambient Standard (ppb) >	120 [5]	75 [6]

[1] Preliminary data subject to change.

[2] Most recent three years of data from the World Data Centre for Greenhouse Gases; http://gaw.kishou.go.jp/cgi-bin/wdcgg/accessdata.cgi?index=BRW471N00-NOAA&select=inventory

[3] This data is the most recent available data available from Alaska DEC for these stations.

[4] Data pertaining to 8-hour average not available at this time. Conservatively assume that the maximum 1-hour concentration persists for 8 hours.

[5] Effective May 27, 2008, EPA revised the 8-hour primary ozone NAAQS, designed to protect public health, to a level of 75 ppb.

An area meets the revised 8-hour standards if the 3-year average of the annual fourth-highest daily maximum 8-hour average at an ozone monitor is less than or equal to the level of the standard (75 ppb).

[6] As of June 15, 2005, EPA revoked its 1-hour ozone standard in all areas except the 8-hour nonattainment Early Action Compact (EAC) areas.

The State of Alaska's Ambient Air Quality Standards for ozone, as amended in its regulations through November 9, 2008, (18 AAC 50.010(4)) are only based on the 1-hour standard of 120 ppb, and the standards for the federal 8-hour standard are not listed in the Alaska regulations.

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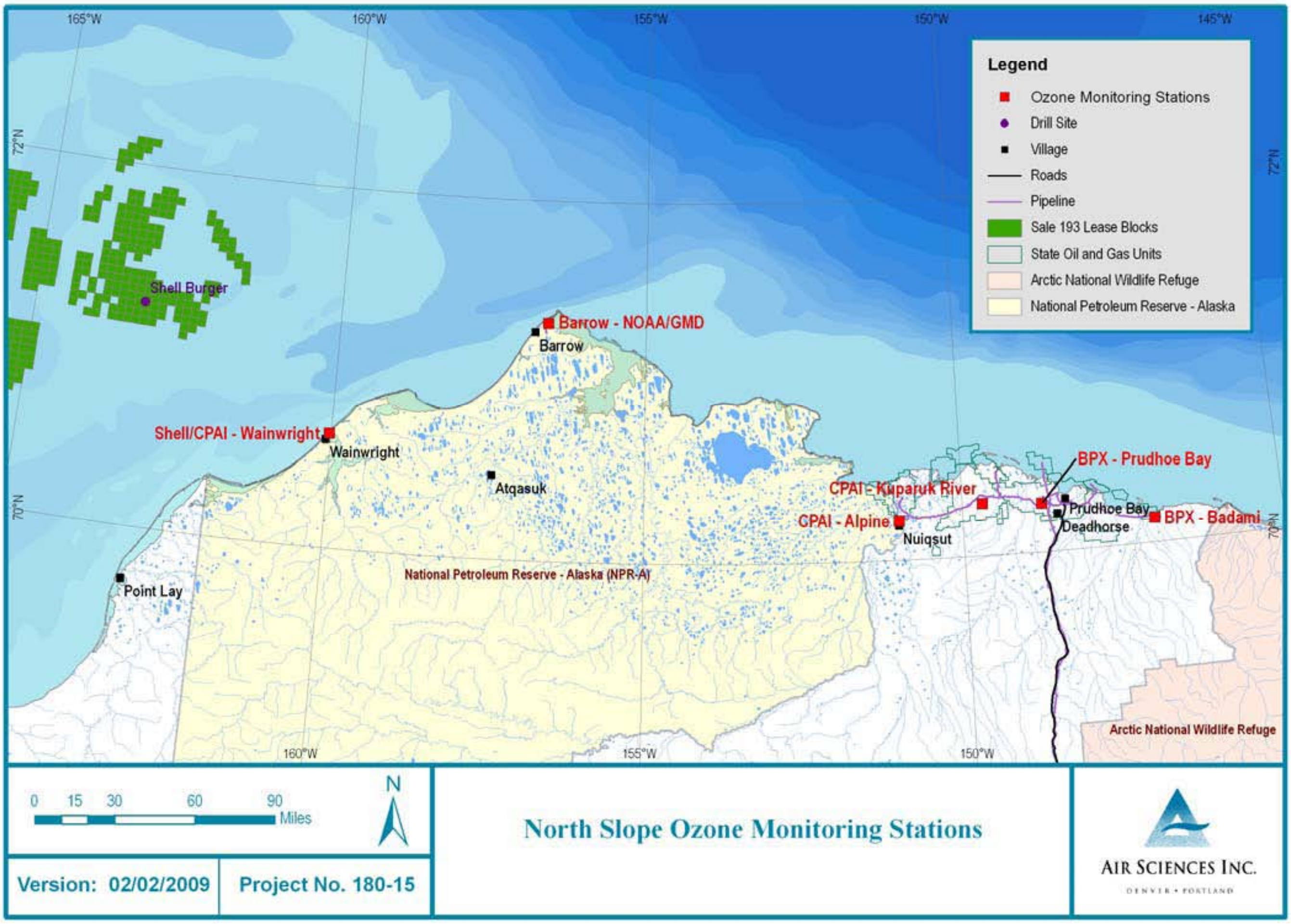
59 U.S. Department of Energy. *Energy Information Administration Webpage*: http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/current/pdf/appb.pdf#page=9

Figure 8-1: Ozone Monitoring Stations on the North Slope



The latest data from the Western Regional Air Partnership (WRAP) Emissions Data Management System (EDMS)[60] indicates North Slope Borough emissions in 2002 (latest year of data available) from all sources (mobile, non-mobile, point, etc.) of NO_x (i.e., an ozone precursor), were approximately 42,500 tons/year and 1,600 tons/year, respectively. Table 8-2 provides a summary of NO_x emissions for point sources (i.e., oil and gas facilities) located in the Deadhorse, Prudhoe Bay, and Kuparuk areas of the North Slope. Existing North Slope point source emissions of NO_x are approximately 41,000 tons/year, which represent 22 times more NO_x than those from the proposed portable Shell project.

Measured ozone concentrations on the more industrialized North Slope, which take into account impacts from much larger sources of ozone precursors, are no more than two thirds of the 8-hour ambient air quality standard (well below the standards). In addition, Shell's proposed project will be located far offshore and its precursor emissions will be sufficiently dispersed before even impacting onshore areas. Given these factors, the proposed Shell exploratory program's emissions contribution to ozone formation is not expected to be significant and the project should not cause or contribute to an exceedance of the ambient standards for ozone.

60 Western Regional Air Partnership (WRAP) Emissions Data Monitoring System (EDMS) Database. *Emissions Inventory Reports (EDMS).* http://vista.cira.colostate.edu/tss/edms.aspx

Table 8-2: Point Source Emissions of NO_x and VOCs – North Slope

Point Source Name	City	Emissions (tons/year) NO_x
Trans Alaska Pipeline System Pump Station 1	North Slope	269
ConocoPhillips Central Production Facility #2	Kuparuk	1,759
BP Exploration (Alaska) - Inc. - Flow Station #2	Prudhoe Bay	1,398
BP Exploration (Alaska) - Inc. - Gathering Center #2 (GC-2)	Prudhoe Bay	1,212
BP Exploration (Alaska) - Inc. - Flow Station #1 (FS-1)	Prudhoe Bay	1,240
BP Exploration (Alaska) - Inc. - Seawater Injection Plant East	Prudhoe Bay	275
BP Exploration (Alaska) - Inc. - Seawater Treatment Plant - PBU	Prudhoe Bay	163
Trans Alaska Pipeline System Pump Station 3	Prudhoe Bay	251
BP Exploration (Alaska) - Inc. - Central Power Station	Prudhoe Bay	3,830
ConocoPhillips Central Production Facility #1	Umiat Meridian - Kuparuk	2,181
BP Exploration (Alaska) - Inc. - Gathering Center #3 (GC-3)	Prudhoe Bay	1,752
BP Exploration (Alaska) - Inc. - Central Gas Facility	Deadhorse	5,695
BP Exploration (Alaska) - Inc. - Milne Point Production Facility	North Slope	517
BP Exploration (Alaska) - Inc. - Badami Development	Deadhorse	64
ConocoPhillips Alpine Central Processing Facility	Umiat Meridian	1,058
BP Exploration (Alaska) - Inc. - Central Compressor Plant	Deadhorse	8,256
Haliburton Energy Services - Inc. - Deadhorse Facility	Deadhorse	235
BP Exploration (Alaska) - Inc. - Endicott Production Facility	Prudhoe Bay	2,700
ConocoPhillips Alaska - Kuparuk Seawater Treatment Plant	Kuparuk	101
BP Exploration (Alaska) - Inc. - Lisburne Production Center	Prudhoe Bay	1,782
ConocoPhillips Alaska - Central Production Facility #3	Kuparuk	1,498
BP Exploration (Alaska) - Inc. - Northstar Production Facility	Deadhorse	326
BP Exploration (Alaska) - Inc. - Gathering Center #1 (GC-1)	Prudhoe Bay	3,060
BP Exploration (Alaska) - Inc. - Flow Station #3	Prudhoe Bay	1,629
	Total >	41,252

APPENDIX A

Short-Term and Seasonal Emissions – One Unit per Page

APPENDIX B

Short-Term Emission Calculation Spreadsheets for Impact Modeling Input

Seasonal Emission Spreadsheets

APPENDIX C

Emission Control Technology Review and References

APPENDIX D

SCREEN3 Model Output for Ice Management Fleet Loads Analyses

APPENDIX E

SCREEN3 Model Output for Plume Rise Determinations

APPENDIX F

Text Footnote References

APPENDIX G

Incinerator Exemption Letter